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

**FORM 10-Q**

(Mark One)

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

For the quarterly period ended September 30, 2005

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

For the transition period from \_\_\_\_\_ to \_\_\_\_\_

**Commission File Number 1-9936**

**EDISON INTERNATIONAL**

(Exact name of registrant as specified in its charter)

**California**

(State or other jurisdiction of  
incorporation or organization)

**95-4137452**

(I.R.S. Employer  
Identification No.)

**2244 Walnut Grove Avenue  
(P. O. Box 976)**

**Rosemead, California**  
(Address of principal executive offices)

**91770**

(Zip Code)

**(626) 302-2222**

(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes  No

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

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 October 31, 2005
Common Stock, no par value	325,811,206

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# EDISON INTERNATIONAL

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**EDISON INTERNATIONAL**  
**PART I FINANCIAL INFORMATION**  
**Item 1. Financial Statements**  
**CONSOLIDATED STATEMENTS OF INCOME**

In millions, except per-share amounts	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
			(Unaudited)	
Electric utility	\$ 3,084	\$ 2,655	\$ 7,194	\$ 6,527
Nonutility power generation	677	509	1,605	1,257
Financial services and other	22	24	79	85
<b>Total operating revenue</b>	<b>3,783</b>	3,188	<b>8,878</b>	7,869
Fuel	489	415	1,309	1,027
Purchased power	502	915	1,633	2,022
Provisions for regulatory adjustment clauses – net	766	(34)	790	(85)
Other operation and maintenance	862	787	2,485	2,367
Asset impairment and loss on lease termination	—	35	12	989
Depreciation, decommissioning and amortization	270	232	796	755
Property and other taxes	51	50	153	148
<b>Total operating expenses</b>	<b>2,940</b>	2,400	<b>7,178</b>	7,223
<b>Operating income</b>	<b>843</b>	788	<b>1,700</b>	646
Interest and dividend income	31	3	78	26
Equity in income from partnerships and unconsolidated subsidiaries – net	27	32	136	61
Other nonoperating income	34	8	70	96
Interest expense – net of amounts capitalized	(198)	(251)	(615)	(741)
Impairment loss on equity method investment	(55)	—	(55)	—
Loss on early extinguishment of debt	—	—	(24)	—
Other nonoperating deductions	(35)	(8)	(58)	(36)
<b>Income from continuing operations before tax and minority interest</b>	<b>647</b>	572	<b>1,232</b>	52
Income tax (benefit)	129	181	267	(40)
Dividends on utility preferred and preference stock not subject to mandatory redemption	7	1	14	4
Minority interest	76	76	142	120
<b>Income (loss) from continuing operations</b>	<b>435</b>	314	<b>809</b>	(32)
Income from discontinued operations – net of tax	27	499	55	570
<b>Income before accounting change</b>	<b>462</b>	813	<b>864</b>	538
Cumulative effect of accounting change – net of tax	—	—	—	(1)
<b>Net income</b>	<b>\$ 462</b>	\$ 813	<b>\$ 864</b>	\$ 537
<b>Weighted-average shares of common stock outstanding</b>	<b>326</b>	326	<b>326</b>	326
<b>Basic earnings (loss) per common share:</b>				
Continuing operations	\$ 1.33	\$ 0.96	\$ 2.47	\$ (0.10)
Discontinued operations	0.08	1.53	0.17	1.75
<b>Total</b>	<b>\$ 1.41</b>	\$ 2.49	<b>\$ 2.64</b>	\$ 1.65
<b>Weighted-average shares, including effect of dilutive securities</b>	<b>332</b>	330	<b>331</b>	330
<b>Diluted earnings (loss) per common share:</b>				
Continuing operations	\$ 1.31	\$ 0.95	\$ 2.45	\$ (0.10)
Discontinued operations	0.08	1.51	0.16	1.73
<b>Total</b>	<b>\$ 1.39</b>	\$ 2.46	<b>\$ 2.61</b>	\$ 1.63
Dividends declared per common share	\$ 0.25	\$ 0.20	\$ 0.75	\$ 0.60

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

**EDISON INTERNATIONAL**

**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

<b>In millions</b>	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2005</b>	<b>2004</b>	<b>2005</b>	<b>2004</b>
			(Unaudited)	
Net income	\$ 462	\$ 813	\$ 864	\$ 537
Other comprehensive income (loss), net of tax:				
Foreign currency translation adjustments:				
Other foreign current translation adjustments – net	1	33	(1)	26
Reclassification adjustment for sale of investment in an international project	—	(134)	—	(134)
Unrealized gain (loss) on investments – net	—	(6)	—	11
Unrealized gains (losses) on cash flow hedges:				
Other unrealized losses on and amortization of cash flow hedges – net	(164)	(1)	(218)	(49)
Reclassification adjustment for gain (loss) included in net income	(72)	27	(80)	70
Other comprehensive loss	(235)	(81)	(299)	(76)
<b>Comprehensive income</b>	<b>\$ 227</b>	<b>\$ 732</b>	<b>\$ 565</b>	<b>\$ 461</b>

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

**EDISON INTERNATIONAL**

**CONSOLIDATED BALANCE SHEETS**

<b>In millions</b>	<b>September 30, 2005</b>	<b>December 31, 2004</b>
	(Unaudited)	
<b>ASSETS</b>		
Cash and equivalents	\$ 2,575	\$ 2,688
Restricted cash	69	73
Margin and collateral deposits	875	108
Receivables, less allowances of \$31 and \$31 for uncollectible accounts at respective dates	1,265	846
Accrued unbilled revenue	429	320
Fuel inventory	86	73
Materials and supplies	245	231
Accumulated deferred income taxes – net	680	288
Trading and price risk management assets	116	41
Regulatory assets	546	553
Other current assets	509	294
<b>Total current assets</b>	<b>7,395</b>	<b>5,515</b>
Nonutility property – less accumulated provision for depreciation of \$1,412 and \$1,311 at respective dates	3,939	3,922
Nuclear decommissioning trusts	2,861	2,757
Investments in partnerships and unconsolidated subsidiaries	505	608
Investments in leveraged leases	2,461	2,424
Other investments	143	131
<b>Total investments and other assets</b>	<b>9,909</b>	<b>9,842</b>
Utility plant, at original cost:		
Transmission and distribution	16,329	15,685
Generation	1,373	1,356
Accumulated provision for depreciation	(4,667)	(4,506)
Construction work in progress	931	789
Nuclear fuel, at amortized cost	146	151
<b>Total utility plant</b>	<b>14,112</b>	<b>13,475</b>
Restricted cash	70	155
Regulatory assets	2,934	3,285
Other deferred charges	1,076	875
<b>Total deferred charges</b>	<b>4,080</b>	<b>4,315</b>
<b>Assets of discontinued operations</b>	<b>12</b>	<b>122</b>
<b>Total assets</b>	<b>\$ 35,508</b>	<b>\$ 33,269</b>

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

**EDISON INTERNATIONAL**

**CONSOLIDATED BALANCE SHEETS**

<b>In millions, except share amounts</b>	<b>September 30, 2005</b>	<b>December 31, 2004</b>
	(Unaudited)	
<b>LIABILITIES AND SHAREHOLDERS' EQUITY</b>		
Short-term debt	\$ —	\$ 88
Long-term debt due within one year	723	809
Preferred stock to be redeemed within one year	—	9
Accounts payable	835	749
Accrued taxes	720	226
Accrued interest	202	233
Counterparty collateral	354	—
Customer deposits	181	168
Book overdrafts	271	232
Trading and price risk management liabilities	597	31
Regulatory liabilities	1,263	490
Other current liabilities	955	1,002
<b>Total current liabilities</b>	<b>6,101</b>	<b>4,037</b>
<b>Long-term debt</b>	<b>8,953</b>	<b>9,678</b>
Accumulated deferred income taxes – net	5,036	5,233
Accumulated deferred investment tax credits	133	138
Customer advances and other deferred credits	1,331	1,109
Power-purchase contracts	76	130
Preferred stock subject to mandatory redemption	—	139
Accumulated provision for pensions and benefits	592	523
Asset retirement obligations	2,268	2,188
Regulatory liabilities	3,302	3,356
Other long-term liabilities	292	232
<b>Total deferred credits and other liabilities</b>	<b>13,030</b>	<b>13,048</b>
<b>Liabilities of discontinued operations</b>	<b>15</b>	<b>15</b>
<b>Total liabilities</b>	<b>28,099</b>	<b>26,778</b>
Commitments and contingencies (Notes 2, 4 and 9)		
<b>Minority interest</b>	<b>314</b>	<b>313</b>
<b>Preferred and preference stock of utility not subject to mandatory redemption</b>	<b>729</b>	<b>129</b>
Common stock (325,811,206 shares outstanding at each date)	2,004	1,975
Accumulated other comprehensive loss	(303)	(4)
Retained earnings	4,665	4,078
<b>Total common shareholders' equity</b>	<b>6,366</b>	<b>6,049</b>
<b>Total liabilities and shareholders' equity</b>	<b>\$ 35,508</b>	<b>\$ 33,269</b>

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

**EDISON INTERNATIONAL**  
**CONSOLIDATED STATEMENTS OF CASH FLOWS**

<b>In millions</b>	<b>Nine Months Ended</b>	
	<b>September 30,</b>	
	<b>2005</b>	<b>2004</b>
	(Unaudited)	
<b>Cash flows from operating activities:</b>		
Income (loss) from continuing operations, after accounting changes, net of tax	\$ 809	\$ (33)
Adjustments to reconcile to net cash provided by operating activities:		
Cumulative effect of accounting change, net of tax	—	1
Depreciation, decommissioning and amortization	796	755
Other amortization	81	79
Minority interest	142	120
Deferred income taxes and investment tax credits	(269)	(140)
Equity in income from partnerships and unconsolidated subsidiaries	(136)	(61)
Income from leveraged leases	(54)	(62)
Regulatory assets – long-term	372	318
Regulatory liabilities – long-term	(92)	(38)
Loss on early extinguishment of debt	24	—
Impairment losses	67	35
Levelized rent expense	(115)	(59)
Other assets	(101)	(50)
Other liabilities	105	50
Margin and collateral deposits – net of collateral received	(413)	(31)
Receivables and accrued unbilled revenue	(580)	(263)
Inventory, prepayments and other current assets	(397)	22
Regulatory assets – short-term	7	(1,050)
Regulatory liabilities – short-term	773	698
Accrued interest and taxes	477	9
Accounts payable and other current liabilities	144	273
Distributions and dividends from unconsolidated entities	40	56
<b>Net cash provided by operating activities</b>	<b>1,680</b>	<b>629</b>
<b>Cash flows from financing activities:</b>		
Long-term debt issued and issuance costs	1,143	3,358
Long-term debt repaid	(1,883)	(2,548)
Bonds remarketed – net	—	350
Issuance of preference stock	592	—
Redemption of preferred securities	(148)	(2)
Rate reduction notes repaid	(177)	(177)
Change in book overdrafts	39	(189)
Short-term debt financing – net	(88)	(263)
Shares purchased for stock-based compensation	(145)	(48)
Proceeds from stock option exercises	78	32
Dividends to minority shareholders	(122)	(90)
Dividends paid	(244)	(195)
<b>Net cash provided (used) by financing activities</b>	<b>\$ (955)</b>	<b>\$ 228</b>

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

**EDISON INTERNATIONAL  
CONSOLIDATED STATEMENTS OF CASH FLOWS**

<b>In millions</b>	<b>Nine Months Ended September 30,</b>	
	<b>2005</b>	<b>2004</b>
	(Unaudited)	
<b>Cash flows from investing activities:</b>		
Capital expenditures	\$ (1,337)	\$ (1,161)
Acquisition costs related to nonutility generation plant	—	(285)
Proceeds from sale of property and interests in projects	—	118
Proceeds from sale of discontinued operations	124	739
Contributions to and earnings from nuclear decommissioning trusts – net	(76)	(62)
Distributions from partnerships and unconsolidated subsidiaries	92	16
Sales of short-term investments – net	140	20
Restricted cash	84	57
Customer advances for construction and other investments	82	(4)
<b>Net cash used by investing activities</b>	<b>(891)</b>	<b>(562)</b>
<b>Effect of consolidation of variable interest entities on cash</b>	<b>3</b>	<b>79</b>
<b>Effect of deconsolidation of variable interest entities on cash</b>	<b>—</b>	<b>(32)</b>
<b>Net changes in cash of discontinued operations</b>	<b>52</b>	<b>51</b>
<b>Effect of exchange rate changes on cash</b>	<b>(1)</b>	<b>—</b>
<b>Net increase (decrease) in cash and equivalents</b>	<b>(112)</b>	<b>393</b>
<b>Cash and equivalents, beginning of period</b>	<b>2,689</b>	<b>2,178</b>
<b>Cash and equivalents, end of period</b>	<b>2,577</b>	<b>2,571</b>
<b>Cash and equivalents, discontinued operations</b>	<b>(2)</b>	<b>(137)</b>
<b>Cash and equivalents, continuing operations</b>	<b>\$ 2,575</b>	<b>\$ 2,434</b>
<b>Supplemental Cash Flow Information:</b>		
<b><u>Cash payments for interest and taxes</u></b>		
Cash payments for interest – net of amounts capitalized	\$ 576	\$ 696
Cash payments for taxes	62	8
<b><u>Non-cash investing and financing activities</u></b>		
Details of debt exchanges:		
Pollution-control bonds redeemed	\$ (452)	—
Pollution-control bonds issued	452	—
Dividends declared but not paid	\$ 81	\$ 65
Details of consolidation of variable interest entities:		
Assets	—	\$ 625
Liabilities	—	(704)
Details of deconsolidation of variable interest entities:		
Assets	—	\$ (133)
Liabilities	—	165
Reoffering of pollution-control bonds	—	\$ 196
Details of pollution-control bond redemption:		
Release of funds held in trust	—	\$ 20
Pollution-control bonds redeemed	—	(20)

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

## **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 for a fair presentation of the financial position, results of operations and cash flows in accordance with accounting principles generally accepted in the United States for the periods covered by this report. The results of operations for the period ended September 30, 2005 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 on Form 10-K for the year ended December 31, 2004 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 2004 Annual Report. Edison International follows the same accounting policies for interim reporting purposes.

Certain prior-period amounts were reclassified to conform to the September 30, 2005 financial statement presentation. Except as indicated, amounts presented in the Notes to the Consolidated Financial Statements relate to continuing operations.

##### ***Counterparty Collateral***

Counterparty collateral includes cash received related to financial gas trading activities.

##### ***Earnings Per Common Share (EPS)***

In March 2004, the Financial Accounting Standards Board (FASB) issued new accounting guidance for the effect of participating securities on EPS calculations and the use of the two-class method. The new guidance, which was effective in second quarter 2004, requires the use of the two-class method of computing EPS for companies with participating securities. The two-class method is an earnings allocations formula that determines EPS for each class of common stock and participating security. Edison International has participating securities (vested stock options that earn dividend equivalents on an equal basis with common shares), but determined that the effect on 2004 EPS was immaterial.

Basic EPS is computed by dividing net income available for common stock by the weighted-average number of common shares outstanding. Net income (loss) available for common stock was \$459 million and \$813 million for the three months ended September 30, 2005, and 2004, respectively, and was \$859 million and \$537 million for the nine months ended September 30, 2005, and 2004, respectively. In arriving at net income, dividends on preferred securities and preferred stock have been deducted.

For the diluted EPS calculation, dilutive securities (stock-based compensation awards exercisable) are added to the weighted-average shares. However, in periods of net loss, dilutive securities are not added to the weighted-average shares due to their antidilutive effect.

## EDISON INTERNATIONAL

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

#### *Income Taxes*

Edison International's effective tax rates were 23% and 25% for the three- and nine-month periods ended September 30, 2005, respectively, as compared to 37% and 55% for the same periods in 2004. The decreased effective tax rates resulted primarily from recording a \$65 million benefit, including \$57 million of interest income, in the third quarter of 2005 related to a settlement reached with the Internal Revenue Service (IRS) on tax issues and pending affirmative claims relating to Edison International's 1991–1993 tax years. Additional decreases to the effective rates resulted from reductions made to accrued tax liabilities in 2005 to reflect progress made in settlement negotiations related to tax audits other than the 1991–1993 tax years, changes in property-related flow-through items at SCE and adjustments made to tax balances in 2005 at MEHC and SCE.

#### *Margin and Collateral Deposits*

Margin and collateral deposits include cash deposited with counterparties and brokers as credit support under margining agreements for power and gas trading activities. The amount of margin and collateral deposits generally varies based on changes in the value of the agreements. Deposits with counterparties and brokers generally earn interest at various rates.

#### *New Accounting Principles*

In March 2005, the FASB issued an interpretation related to accounting for conditional asset retirement obligations (AROs). This Interpretation clarifies that an entity is required to recognize a liability for the fair value of a conditional ARO if the fair value can be reasonably estimated even though uncertainty exists about the timing and/or method of settlement. This Interpretation is effective December 31, 2005. Thus far, Edison International has identified conditional AROs related to: treated wood poles, hazardous materials such as mercury and polychlorinated biphenyls-containing equipment; and asbestos removal costs at buildings, operating stations and retired units. Additional assessment is necessary to value these AROs. However, since SCE follows accounting principles for rate-regulated enterprises and receives recovery of these costs through rates, implementation of this interpretation at SCE will not affect Edison International's earnings. Implementation of this interpretation at Edison Mission Energy (EME) is expected to have a minimal impact on Edison International's earnings.

A new accounting standard requires companies to use the fair value accounting method for stock-based compensation. Edison International currently uses the intrinsic value accounting method for stock-based compensation. On April 14, 2005, the Securities and Exchange Commission announced a delay in the effective date for the new standard to fiscal years beginning after June 15, 2005. Edison International will implement the new standard effective January 1, 2006 by applying the modified prospective transition method. The difference in expense between the two accounting methods related to stock options granted is shown below under "Stock-Based Compensation." Edison International is assessing the impact of this accounting standard on its performance shares.

The American Jobs Creation Act of 2004 included a tax deduction on qualified production activities income (including income from the sale of electricity). In December 2004, the FASB issued guidance that this deduction should be accounted for as a special deduction, rather than a tax rate reduction. Accordingly, the special deduction is recorded in the year it is earned. In October 2005, the IRS issued proposed regulations for this tax deduction. The tax deduction is not expected to materially affect Edison International's 2005 financial statements. Edison International is evaluating the effect that the manufacturer's deduction will have in subsequent years.

## **EDISON INTERNATIONAL**

### **NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

In March 2004, the FASB issued new accounting guidance for the effect of participating securities on EPS calculations and the use of the two-class method. The new guidance, which was effective in second quarter 2004, requires the use of the two-class method of computing EPS for companies with participating securities (including vested stock options with dividend equivalents). See “Earnings Per Common Share” above.

In December 2003, the FASB issued a revision to an accounting Interpretation (originally issued in January 2003), Consolidation of Variable Interest Entities (VIEs). The primary objective of the Interpretation is to provide guidance on the identification of, and financial reporting for, VIEs, where control may be achieved through means other than voting rights. Under the Interpretation, the enterprise that is expected to absorb or receive the majority of a VIE’s expected losses or residual returns, or both, must consolidate the VIE, unless specific exceptions apply. This Interpretation was effective for special purpose entities, as defined by accounting principles generally accepted in the United States, as of December 31, 2003, and all other entities as of March 31, 2004. Edison International implemented the Interpretation for its special purpose entities as of December 31, 2003.

On March 31, 2004, SCE consolidated four power projects partially owned by EME, EME deconsolidated two power projects, and Edison Capital consolidated two affordable housing partnerships and three wind projects. Edison International recorded a cumulative effect adjustment that decreased net income by less than \$1 million, net of tax, due to negative equity at one of Edison Capital’s newly consolidated entities.

**EDISON INTERNATIONAL**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

*Regulatory Assets and Liabilities*

Regulatory assets included in the consolidated balance sheets are:

In millions	<b>September 30, December 31,</b>	
	<b>2005</b>	<b>2004</b>
	(Unaudited)	
<u>Current</u>		
Regulatory balancing accounts	\$ 348	\$ 371
Direct access procurement charges	112	109
Purchased-power settlements	57	62
Other	29	11
	<b>546</b>	<b>553</b>
<u>Long-term</u>		
Flow-through taxes – net	1,008	1,018
Rate reduction notes – transition cost deferral	520	739
Unamortized nuclear investment – net	493	526
Nuclear-related ARO investment – net	261	272
Unamortized coal plant investment – net	81	78
Unamortized loss on reacquired debt	328	250
Direct access procurement charges	63	141
Environmental remediation	55	55
Purchased-power settlements	50	91
Other	75	115
	<b>2,934</b>	<b>3,285</b>
<b>Total regulatory assets</b>	<b>\$ 3,480</b>	<b>\$ 3,838</b>

## EDISON INTERNATIONAL

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Regulatory liabilities included in the consolidated balance sheets are:

In millions	September 30,	December 31,
	2005	2004
	(Unaudited)	
<u>Current</u>		
Regulatory balancing accounts	\$ 680	\$ 357
Direct access procurement charges	112	109
Energy derivatives	398	—
Other	73	24
	<u>1,263</u>	<u>490</u>
<u>Long-term</u>		
ARO	806	819
Costs of removal	2,151	2,112
Direct access procurement charges	63	141
Employee benefits plans	235	200
Energy derivatives	47	—
Other	—	84
	<u>3,302</u>	<u>3,356</u>
<b>Total regulatory liabilities</b>	<b>\$ 4,565</b>	<b>\$ 3,846</b>

SCE's regulatory liabilities related to energy derivatives are an offset to unrealized gains on recorded derivatives.

#### *Stock-Based Compensation*

Edison International has three stock-based compensation plans, which are described more fully in Note 7 of "Notes to Consolidated Financial Statements" included in its 2004 Annual Report. Edison International accounts for these plans using the intrinsic value method. Upon grant, no stock-based compensation cost is reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The following table illustrates the effect on net income and EPS if Edison International had used the fair-value accounting method for stock options granted.

**EDISON INTERNATIONAL**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

In millions, except per-share amounts	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
			(Unaudited)	
Net income, as reported	\$ 462	\$ 813	\$ 864	\$ 537
Add: stock-based compensation expense using the intrinsic value accounting method – net of tax	18	3	44	11
Less: stock-based compensation expense using the fair-value accounting method – net of tax	20	3	51	10
<b>Pro forma net income</b>	<b>\$ 460</b>	<b>\$ 813</b>	<b>\$ 857</b>	<b>\$ 538</b>
Basic earnings per common share:				
As reported	\$ 1.41	\$ 2.49	\$ 2.64	\$ 1.65
Pro forma	\$ 1.40	\$ 2.49	\$ 2.61	\$ 1.65
Diluted earnings per common share:				
As reported	\$ 1.39	\$ 2.46	\$ 2.61	\$ 1.63
Pro forma	\$ 1.38	\$ 2.46	\$ 2.57	\$ 1.63

***Supplemental Accumulated Other Comprehensive Loss Information***

Supplemental information regarding Edison International’s accumulated other comprehensive loss, including discontinued operations, is:

In millions	September 30, 2005	December 31, 2004
	(Unaudited)	
Foreign currency translation adjustments	\$ 1	\$ —
Minimum pension liability – net	(16)	(15)
Unrealized gains (losses) on cash flow hedges – net	(288)	11
<b>Accumulated other comprehensive loss</b>	<b>\$ (303)</b>	<b>\$ (4)</b>

The minimum pension liability is discussed in Note 7, Compensation and Benefit Plans of “Notes to Consolidated Financial Statements” included in Edison International’s 2004 Annual Report.

Included in Edison International’s accumulated other comprehensive loss at September 30, 2005, was a \$283 million loss related to EME’s net unrealized losses on cash flow hedges and a \$5 million loss related to SCE’s interest rate swap (see discussion below).

Unrealized losses on cash flow hedges at September 30, 2005, include unrealized losses on commodity hedges primarily related to EME’s Midwest Generation and Homer City futures and forward electricity contracts that qualify for hedge accounting. These losses arise because current forecasts of future electricity prices in these markets are greater than contract prices. The increase in the unrealized losses during the third quarter of 2005 resulted from a combination of new hedges for 2006 and 2007 and an increase in market prices for power driven largely from higher natural gas and oil prices. In addition, at September 30, 2005, EME reclassified a \$9 million, after tax, unrealized gain from other comprehensive loss to earnings due to the impairment of its equity investment in the March Point project. Unrealized losses on cash flow hedges also included those related to SCE’s interest rate swap (the swap terminated on January 5, 2001, but the related debt matures in 2008). The unamortized loss of \$5 million

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(as of September 30, 2005, net of tax) on the interest rate swap will be amortized over a period ending in 2008. Approximately \$2 million, after tax, of the unamortized loss on this swap will be reclassified into earnings during the next 12 months. Amortized losses are recoverable through SCE's annual cost of capital proceeding.

As EME's hedged positions for continuing operations are realized, approximately \$257 million, after tax, of the net unrealized losses on cash flow hedges at September 30, 2005 are expected to be reclassified into earnings during the next 12 months. EME expects that reclassification of net unrealized losses will offset energy revenue recognized at market prices. Actual amounts ultimately reclassified into earnings over the next 12 months could vary materially from this estimated amount as a result of changes in market conditions. The maximum period over which a cash flow hedge is designated is through December 31, 2007.

EME recorded net losses of approximately \$32 million and \$13 million during the third quarter of 2005 and 2004, respectively, and \$35 million and \$9 million during the nine months ended September 30, 2005 and 2004, respectively, which represented the amount of cash flow hedges' ineffectiveness for continuing operations; these amounts are reflected in nonutility power generation revenue in the consolidated income statements.

#### **Note 2. Regulatory Contingencies**

Further information on these regulatory contingencies is described in Note 2 of "Notes to Consolidated Financial Statements" included in Edison International's 2004 Annual Report. See Note 4 for additional contingencies.

#### ***California Department of Water Resources (CDWR) Power Purchases and Revenue Requirement Proceedings***

As discussed in the "CDWR Power Purchases and Revenue Requirement Proceedings" disclosure in Note 2 of "Notes to Consolidated Financial Statements" included in Edison International's 2004 Annual Report, in December 2004, the California Public Utilities Commission (CPUC) issued its decision on how the CDWR's power charge revenue requirement for 2004 through 2013 would be allocated among the investor-owned utilities. On June 30, 2005, the CPUC granted, in part, San Diego Gas & Electric's (SDG&E) petition for modification of the December 2004 decision. The June 30, 2005 decision adopted a methodology that retains the cost-follows-contract allocation of the avoidable costs, and allocates the unavoidable costs associated with the contracts: 42.2% to Pacific Gas and Electric's (PG&E) customers, 47.5% to SCE's customers and 10.3% to SDG&E's customers. This newly adopted allocation methodology decreases the total costs allocated to SDG&E's customers and increases the total costs allocated to SCE's and PG&E's customers, relative to the December 2004 decision.

The burden of the additional costs, relative to the December 2004 decision, is borne almost entirely by SCE's customers for the period 2004–2009, and then shifts almost entirely to PG&E's customers in 2010–2011, when contract deliveries of the CDWR energy to PG&E's customers falls by approximately 75%. SCE, joined by The Utility Reform Network and the California Large Electricity Consumers Association, filed a petition for modification of the June 30, 2005 decision, seeking to levelize the allocation of additional costs under the decision to SCE's and PG&E's customers and requesting clarification on other implementation issues. On November 2, 2005, the CPUC issued a proposed decision denying the petition for modification. The final decision is expected in December 2005.

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The CDWR has submitted its 2006 revenue requirement determination to the CPUC for implementation. The CPUC must issue its final decision implementing the 2006 CDWR revenue requirement in December 2005. The November 2, 2005 proposed decision mentioned above also implements the CDWR's 2006 revenue requirement. A final decision is expected in December 2005.

Amounts billed to SCE's customers for electric power purchased and sold by the CDWR are remitted directly to the CDWR and are not recognized as revenue by SCE and therefore have no impact on SCE's earnings.

#### *Demand-Side Management and Energy Efficiency Performance Incentive Mechanisms*

Under a variety of incentive mechanisms adopted by the CPUC in the past, SCE was entitled to certain shareholder incentives for its performance achievements in delivering demand-side management and energy efficiency programs. On June 10, 2005, SCE and the ORA executed a settlement agreement for SCE's outstanding issues concerning SCE shareholder incentives and performance achievements resulting from the demand-side management, energy efficiency, and low-income energy efficiency programs from program years 1994–2004. In addition, the settlement addresses shareholder incentives and performance achievements for program years 1994–1998, anticipated but not yet claimed. The settlement agreement recommends, among other things, that SCE be entitled to immediately recover 92% of the total of SCE's current claims and future claims related to SCE's pre-1998 energy efficiency programs. SCE's total claim for program years 1994–2004 made in 2000 through 2008, including interest, franchise fees and uncollectibles, is approximately \$46 million. On October 27, 2005, the CPUC approved the settlement agreement which found it reasonable for SCE to recover approximately \$42 million of these claims which include all of SCE's outstanding claims, as well as future claims related to SCE's pre-1998 energy efficiency programs (of which approximately \$9 million has already been collected in rates). The remaining portion of claims in the amount of \$33 million will be recognized in the fourth quarter of 2005. As a result of the decision, during the third quarter of 2005, SCE recognized \$14 million of incentives previously awarded for which revenue recognition was deferred pending final resolution of these matters. The \$14 million is reflected in the income statement caption "Other nonoperating income." In addition, \$4 million related to interest on the claims was reflected in the caption "Interest and dividend income."

#### *Energy Resource Recovery Account (ERRA) Proceedings*

In an October 2002 decision, the CPUC established the Energy Resource Recovery Account (ERRA) as the rate-making mechanism to track and recover SCE's: (1) fuel costs related to its generating stations; (2) purchased-power costs related to cogeneration and renewable contracts; (3) purchased-power costs related to existing interutility and bilateral contracts that were entered into before January 17, 2001; and (4) new procurement-related costs incurred on or after January 1, 2003 (the date on which the CPUC transferred back to SCE the responsibility for procuring energy resources for its customers). SCE recovers these costs on a cost-recovery basis, with no markup for return or profit. SCE files annual forecasts of the above-described costs that it expects to incur during the following year. As these costs are subsequently incurred, they will be tracked and recovered through the ERRA, but are subject to a reasonableness review in a separate annual ERRA application. If the ERRA overcollection or

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### **NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

undercollection exceeds 5% of SCE's prior year's generation revenue, the CPUC has established a "trigger" mechanism, whereby SCE can request an emergency rate adjustment in addition to the annual forecast and reasonableness ERRA applications.

#### *ERRA Reasonableness Review for the Period January 1, 2004 through December 31, 2004*

On April 1, 2005, SCE submitted an ERRA review application requesting that the CPUC find its procurement-related costs for calendar year 2004 to be reasonable, and that its contract administration and economic dispatch operations during 2004 complied with its CPUC-adopted procurement plan. In addition, SCE requested recovery of approximately \$13 million associated with Nuclear Unit Incentive Procedure rewards for efficient operation of the Palo Verde Nuclear Generating Station (Palo Verde) and approximately \$7 million in administrative and general costs incurred to carry out the CPUC's directive to begin procuring energy supplies on January 1, 2003 following the California energy crisis. In August 2005, the ORA recommended a \$16 million disallowance associated with SCE's 2004 sales of energy in the hour-ahead market, alleging that the price at which SCE sold its hour-ahead energy was unreasonable. SCE submitted its rebuttal testimony on September 15, 2005, contesting the ORA's recommendation. In addition, in its opening briefs, the ORA recommended that SCE be penalized \$37 million for allegedly having failed to prove that its least-cost dispatch operations complied with the methodology presented by the ORA. SCE believes the disallowance and recommended penalty are without merit. A decision is expected by the end of 2005.

#### *Generation Procurement Proceedings*

SCE resumed power procurement responsibilities for its net-short position (expected load requirements exceed generation supply) on January 1, 2003, pursuant to CPUC orders and California statutes passed in 2002. The current regulatory and statutory framework requires SCE to assume limited responsibilities for CDWR contracts allocated by the CPUC, and provide full power procurement responsibilities on the basis of annual short-term procurement plans, long-term resource plans and increased procurement of renewable resources. Currently, the CPUC and the California Energy Commission are working together to set rules for various aspects of generation procurement which are described below.

#### *Procurement Plan*

In December 2003, the CPUC adopted a short-term procurement plan for SCE which established a target level for spot market purchases equal to 5% of monthly need, and allowed SCE to enter into contracts of up to five years. Currently, SCE is operating under this approved short-term procurement plan. To the extent SCE procures power in accordance with the plan, SCE receives full-cost recovery of its procurement transactions pursuant to Assembly Bill 57. Accordingly, the plan is referred to as the Assembly Bill 57 component of the procurement plan.

Each quarter, SCE is required to file a report with the CPUC demonstrating that SCE's procurement-related transactions associated with serving the demands of its bundled electricity customers were in conformance with SCE's adopted short-term procurement plan. SCE has submitted quarterly compliance filings covering the period from January 1, 2003 through September 30, 2005. The CPUC issued one resolution approving SCE's first compliance report for the period January 1, 2003 to March 31, 2003 and issued a resolution approving the other transactions for calendar year 2003 in a June 16, 2005 resolution.

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### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

#### *Resource Adequacy Requirements*

Under the framework adopted in the CPUC's January 22, 2004 decision, all load-serving entities in California have an obligation to procure sufficient resources to meet their customers' needs. On October 27, 2005, the CPUC issued a decision clarifying the January 2004 decision and a subsequent October 2004 decision on resource adequacy requirement. The October 2005 decision requires load-serving entities to ensure that adequate resources have been contracted to meet that entity's peak forecasted energy resource demand and an additional planning reserve margin of 15-17% in every month of the year, beginning in June 2006. The October 2005 decision requires that SCE demonstrate that it has contracted 90% of its June–September 2006 resource adequacy requirement by January 2006. By the end of May 2006, SCE will be required to fill out the remaining 10% of its resource adequacy requirement one month in advance of expected need. A month-ahead showing demonstrating that SCE has procured 100% of its resource adequacy requirement will be required every month thereafter. The October 2005 decision also adopted limits on the amount of a portfolio-sourced, as opposed to a unit-specific, firm energy contract that can be used to meet a load serving entity's resource adequacy requirement. Under the October 2005 decision, a load-serving entity can have no more than 75% of its portfolio of resource adequacy resources met by such contracts in 2006, no more than 50% met by such contracts in 2007, and no more than 25% met by such contracts in 2008. No such contracts can be used to meet a load-serving entities' resource adequacy requirement after December 31, 2008. The October 2005 decision also clarified that the CDWR contracts, some of which are firm energy contracts, are not subject to the limitations. Additionally, the October 2005 decision adopted minimum elements for contracts upon which load-serving entities' may rely on to meet their resource adequacy obligations. Further, the October 2005 decision deferred implementation of a local resource adequacy requirement until 2007. Lastly, the October 2005 decision adopted penalties of 150% of the cost of new monthly capacity for load serving entities that fail to acquire sufficient resources in 2006, and a 300% penalty in 2007 and beyond. SCE expects to meet its resource adequacy requirements by the deadlines set forth in the decision.

In July 2005, SCE issued a Request for Offers (RFO) whereby SCE solicited offers from sellers in the ISO control area for products that provide capacity, energy and resource adequacy benefits. In early October, SCE executed a number of contracts for these products for terms up to 56 months.

#### *Procurement of Renewable Resources*

SCE's 2005 renewable procurement plan for 2005 through 2014 was filed on March 7, 2005. On July 21, 2005, the CPUC issued a decision approving SCE's renewable procurement plan for 2005 and deferred a ruling on SCE's renewable procurement plan for 2006 through 2014. This decision also approved the methodology advocated by SCE for determining the amount by which reported renewable procurement should be adjusted to reflect line losses. On October 6, 2005, the CPUC issued a decision conditionally approving SCE's renewable procurement plan for 2006 through 2014.

The CPUC's July 21, 2005 decision referenced above states that SCE cannot count procurement from certain geothermal facilities towards its 1% annual renewable procurement requirement, unless such procurement is from production certified as "incremental" by the California Energy Commission. A 2003 CPUC decision had held that SCE could count procurement from these geothermal facilities toward its 1% annual renewable procurement requirement. SCE is currently pursuing reconsideration of the July 21, 2005 decision.

The geothermal facilities have applied to the California Energy Commission for certification of a portion of the facilities' production as "incremental." A decision from the California Energy Commission is expected in November 2005. It is not clear whether any of the facilities' production will be certified as

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### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

“incremental” or how much, if any, of the “incremental” production from the facilities will be allocated to SCE’s procurement under its contract with the facilities if the California Energy Commission certification is granted.

Depending upon the amount, if any, of California Energy Commission certified “incremental” production allocated to SCE’s procurement under its contract and the manner in which the CPUC implements its flexible rules for compliance with renewable procurement obligations, the CPUC could deem SCE to be out of compliance with its statutory renewable procurement obligations for the years 2003, 2004 and 2005, and therefore SCE could be subject to penalties for those years. In addition, the California Energy Commission’s and the CPUC’s treatment of the production from the geothermal facilities could result in SCE being deemed to be out of compliance with its obligations for 2006. The maximum penalty for noncompliance is \$25 million per year. To comply with renewable procurement mandates and avoid penalties for years beyond 2006, SCE will either need to sign new contracts and/or extend existing renewable qualifying facility contracts.

SCE received bids for renewable resource contracts in response to a solicitation it made in August 2003 and conducted negotiations with bidders regarding potential procurement contracts. On June 30, 2005, the CPUC issued a resolution approving six renewable contracts resulting from the solicitation. On August 11, 2005 and August 31, 2005, SCE submitted advice letters seeking CPUC approval of two additional renewable contracts resulting from the solicitation.

The CPUC’s July 21, 2005 decision referenced above also approved SCE’s proposed new request for proposals for additional renewable contracts. SCE issued its 2005 request for proposals for renewable contracts on September 2, 2005. Proposals for renewable contracts have been received and are being evaluated.

#### *Request for Offers for New Generation Resources*

According to California state agencies, beginning in 2006, there is a need for new generation capacity in southern California. SCE has issued an RFO for new generation resources. SCE solicited offers for power-purchase agreements lasting up to 10 years from new generation facilities with delivery under the agreement beginning between June 1, 2006 and August 1, 2008. SCE filed an application with the CPUC seeking approval of the RFO and the power-purchase agreements executed under the RFO. SCE sought recovery of the costs of the contracts, through the Federal Energy Regulatory Commission (FERC)-jurisdictional rates, from all affected customers. In addition, SCE sought CPUC assurance of full cost recovery in CPUC-approved rates, if the FERC denies any recovery. On September 9, 2005, the CPUC issued a scoping memorandum rejecting SCE’s proposal. Since the scoping memorandum did not provide a mechanism for SCE to secure new generation on behalf of these customers, SCE terminated its RFO and moved to stay the proceeding and withdraw the CPUC application. A stay was granted on September 22, 2005. The motion to withdraw is still pending.

#### *Holding Company Proceeding and Order Instituting Rulemaking (OIR)*

In April 2001, the CPUC issued an order instituting investigation that reopened the past CPUC decisions authorizing utilities to form holding companies and initiated an investigation into, among other things: (1) whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; (2) any additional suspected violations of laws or CPUC rules and decisions; and (3) whether additional rules, conditions, or other changes to the holding company decisions are necessary. For a discussion of item (1) above, see the “Holding Company Proceeding” disclosure in

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### **NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

Note 2 of “Notes to Consolidated Financial Statements” included in Edison International’s 2004 Annual Report.

On May 5, 2005, the CPUC issued a final decision that closed the proceeding. However, because the CPUC closed the proceeding without addressing some of the issues the proceeding raised (such as the appropriateness of the large utilities’ holding company structure and dividend policies), the CPUC may rule on or investigate these issues in the future.

On October 27, 2005, the CPUC issued an OIR to allow the CPUC to re-examine the relationships of the major California energy utilities with their parent holding companies and nonregulated affiliates. The OIR was issued in part in response to the recent repeal of the Public Utility Holding Company Act of 1935.

By means of the OIR, the CPUC will consider whether additional rules to supplement existing rules and requirements governing relationships between the public utilities and their holding companies and nonregulated affiliates should be adopted. Any additional rules will focus on whether (1) the public utilities retain enough capital or access to capital to meet their customers’ infrastructure needs and (2) mitigation of potential conflicts between ratepayer interests and the interests of holding companies and affiliates that could undermine the public utilities’ ability to meet their public service obligations at the lowest cost. The CPUC expects to issue proposed rules in January 2006, and a final decision is expected in March 2006.

#### ***California Independent System Operator (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 charges. The order reversed an arbitrator’s award that had affirmed the ISO’s characterization in May 2000 of the charges as Intra-Zonal Congestion costs and allocation of those charges to Scheduling Coordinators (SCs) in the affected zone within the ISO transmission grid. The April 20, 2004 order directed the ISO to shift the costs from SCs in the affected zone to the responsible Participating Transmission Owner, SCE, and to do so within 60 days of the April 20, 2004 order. Under the April 20, 2004 order, which was stayed pending resolution of SCE’s rehearing request, SCE would be charged a certain amount as the Participating Transmission Owner but also would be credited in its role as an SC and through the California Power Exchange, to the extent it acted as SCE’s SC. On March 30, 2005, the FERC issued an Order Denying Rehearing. SCE obtained an extension of the stay pending resolution of the appeal SCE has filed with the Court of Appeals for the D.C. Circuit. A briefing schedule has been set in the appeal with SCE’s opening brief due on December 23, 2005. The potential net impact on SCE is estimated to be approximately \$20 million to \$25 million, including interest. SCE filed a request for clarification with the FERC asking the FERC to clarify that SCE can reflect and recover the disputed costs in SCE’s reliability services rates. On June 8, 2005, the FERC denied the clarification, noting that during the appeal, the FERC’s order is stayed; and therefore SCE is not required to pay at this time. SCE may seek recovery in its reliability service rates of the costs should SCE be required to pay these costs.

#### ***Mohave Generating Station and Related Proceedings***

As discussed in the “Mohave Generating Station and Related Proceedings” disclosure in Note 2 of “Notes to Consolidated Financial Statements” included in Edison International’s 2004 Annual Report, the CPUC issued a final decision in December 2004 on SCE’s application regarding the post-2005 operation of Mohave, which is partly owned by SCE.

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In parallel with and since the conclusion of the CPUC proceeding, negotiations, water studies and other efforts have continued among the relevant parties in an attempt to resolve Mohave's post-2005 coal and water supply issues. Although progress has been made with respect to certain issues, no complete resolution has been reached to date. Because resolution has not been reached and because of the lead times required for installation of certain pollution-control equipment and other upgrades necessary for post-2005 operation, it appears probable that Mohave will temporarily shut down at the end of 2005, and a permanent shutdown remains possible. The outcome of the efforts to resolve the post-2005 coal and water supply issues is not expected to impact Mohave's operation through 2005, but the presence or absence of Mohave as an available resource beyond 2005 will impact SCE's long-term resource plan. SCE's 2006 ERRA forecast application assumes Mohave is an unavailable resource for power for 2006. Because SCE expects to recover Mohave shut-down costs in future rates, the outcome of this matter is not expected to have a material impact on earnings.

For additional matters related to Mohave, see "Navajo Nation Litigation" in Note 4.

#### ***System Reliability Incentive Mechanism***

SCE's 2003 General Rate Case (GRC) decision provided for performance incentives or penalties for differences between SCE's actual results and CPUC-authorized standards for system reliability measures beginning in 2004. In a March 30, 2005 advice letter, SCE reported a \$2 million penalty and recorded an accrual in 2004 for its 2004 results under the modified reliability mechanism. On April 28, 2005, the CPUC agreed to suspend its review of SCE's advice letter for 2004 results until the CPUC's Consumer Protection and Safety Division (CPSD) has completed its investigation regarding performance incentive rewards discussed in Note 4. Based on preliminary recorded data through September 2005 and a forecast of normal results through December 2005, SCE projects it will incur a penalty of \$26 million under the reliability performance mechanism for 2005. The maximum penalty that could be assessed under the reliability performance mechanism is approximately \$40 million. As a result, during the third quarter of 2005, SCE recorded an accrual of \$26 million that is reflected in the income statement caption "Other nonoperating deductions."

#### ***Transmission Proceeding***

In August and November 2002, the FERC issued opinions affirming a September 1999 administrative law judge decision to disallow, among other things, recovery by SCE and the other California public utilities of costs reflected in network transmission rates associated with ancillary services and losses incurred by the utilities in administering existing wholesale transmission contracts after implementation of the restructured California electric industry. SCE has incurred approximately \$80 million of these unrecovered costs since 1998. In addition, SCE has accrued interest on these unrecovered costs. The three California utilities appealed the decisions to the Court of Appeals for the Federal Circuit. On July 12, 2005, the Court of Appeals for the Federal Circuit vacated the FERC's August and November 2002 orders, and remanded the case to the FERC for further proceedings. SCE believes that the Court of Appeals for the Federal Circuit's decision increases the likelihood that it will recover these costs.

#### ***Wholesale Electricity and Natural Gas Markets***

As discussed in the "Wholesale Electricity and Natural Gas Markets" disclosure in Note 2 of "Notes to Consolidated Financial Statements" included in Edison International's 2004 Annual Report, SCE is participating in several related proceedings seeking recovery of refunds from sellers of electricity and natural gas who allegedly manipulated the electric and natural gas markets.

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El Paso Natural Gas Company (El Paso) entered into a settlement agreement with a number of parties (including SCE, PG&E, the State of California and various consumer class action representatives) settling various claims stated in proceedings at the FERC and in San Diego County Superior Court that El Paso had manipulated interstate capacity and engaged in other anticompetitive behavior in the natural gas markets in order to unlawfully raise gas prices at the California border in 2000–2001. The United States District Court has issued an order approving the stipulated judgment and the settlement agreement has become effective. Pursuant to a CPUC decision, SCE was required to refund to customers amounts received under the terms of the El Paso settlement (net of legal and consulting costs) through its ERRRA mechanism. In June 2004, SCE received its first settlement payment of \$76 million. Approximately \$66 million of this amount was credited to purchased-power expense, and was refunded to SCE's ratepayers through the ERRRA over the following twelve months, and the remaining \$10 million was used to offset SCE's incurred legal costs. El Paso has elected to prepay the additional settlement payments due over a 20-year period and, as a result, SCE received \$66 million in May 2005. Amounts El Paso refunds to the CDWR will result in reductions in the CDWR's revenue requirement allocated to SCE in proportion to SCE's share of the CDWR's power charge revenue requirement.

On January 14, 2005, SCE, PG&E, SDG&E and several governmental entities agreed to settlement terms with Mirant Corporation and a number of its affiliates (collectively Mirant), all of whom are debtors in Chapter 11 bankruptcy proceedings pending in Texas. Among other things, the settlement terms provide for cash and equivalent refunds totaling \$320 million, of which SCE's allocated share is approximately \$68 million. The settlement also provides for an allowed, unsecured claim totaling \$175 million in the bankruptcy of one of the Mirant parties, with SCE being allocated approximately \$33 million of the unsecured claim. The actual value of the unsecured claim will be determined as part of the resolution of the Mirant parties' bankruptcies. The Mirant settlement was approved by the FERC on April 13, 2005 and by the bankruptcy court on April 15, 2005. In April and May 2005, SCE received its allocated \$68 million in cash settlement proceeds. SCE continues to hold its \$33 million share of the allowed, unsecured bankruptcy claim. The Mirant settlement will be refunded to ratepayers as described below.

On July 15, 2005, SCE, PG&E, SDG&E and several governmental entities agreed to settlement terms with Enron Corporation and a number of its affiliates (collectively Enron), most of which are debtors in Chapter 11 bankruptcy proceedings pending in New York. Among other things, the settlement terms provide for cash and equivalent payments from Enron totaling approximately \$47 million and an allowed, unsecured claim in the bankruptcy against one of the Enron entities in the amount of \$875 million. SCE's allocable share of both the cash and allowed claim portions of the settlement consideration has not yet been finally determined, and the value of an allocable share of the allowed claim will be determined as part of the resolution of the Enron parties' bankruptcies. The settlement was approved by the Enron bankruptcy court on October 20, 2005, but remains subject to approval by the FERC. Effective August 24, 2005, the CPUC approved the settlement by entering into an agreement incorporating its terms. The Enron settlement proceeds will be refunded to ratepayers as described below.

On August 12, 2005, SCE, PG&E, SDG&E, several governmental entities and certain other parties agreed to settlement terms with Reliant Energy, Inc. and a number of its affiliates (collectively Reliant). Among other things, the settlement terms provide for Reliant to provide cash and cash equivalents having a total value of at least \$460 million, which would be in addition to the \$65 million in refunds that Reliant was already required to provide pursuant to FERC orders. SCE expects that its allocable share of the entire settlement value of \$525 million (including the amounts previously ordered by the FERC) will be approximately \$130 million. The settlement remains subject to FERC approval, which is anticipated in the first quarter of 2006. Effective October 12, 2005, the CPUC approved the settlement by entering into

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an agreement incorporating its terms. The Reliant settlement proceeds will be refunded to ratepayers as described below.

On November 19, 2004, the CPUC issued a resolution authorizing SCE to establish an Energy Settlement Memorandum Account (ESMA) for the purpose of recording the foregoing settlement proceeds (excluding the El Paso settlement) from energy providers and allocating them in accordance with the terms of the October 2001 settlement agreement entered into by SCE and the CPUC which settled SCE's lawsuit against the CPUC. This lawsuit sought full recovery of SCE's electricity procurement costs incurred during the energy crisis. The resolution provides a mechanism whereby portions of the settlement proceeds recorded in the ESMA will be allocated to recovery of SCE's litigation costs and expenses in the FERC refund proceedings described above and a 10% shareholder incentive pursuant to the CPUC litigation settlement agreement. Remaining amounts for each settlement are to be refunded to ratepayers through the ERRRA mechanism. In the second quarter of 2005, SCE recorded a \$7 million increase to other nonoperating income as a shareholder incentive related to the Mirant refund received during the second quarter of 2005.

#### Note 3. Pension Plans and Postretirement Benefits Other Than Pensions

##### *Pension Plans*

Edison International previously disclosed in Note 7 of "Notes to Consolidated Financial Statements" included in Edison International's 2004 Annual Report that it expects to contribute approximately \$53 million to its pension plans in 2005. As of September 30, 2005, \$15 million in contributions have been made. Edison International anticipates that its original expectation will be met by year-end 2005.

Expense components are:

In millions	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
			(Unaudited)	
Service cost	\$ 29	\$ 26	\$ 87	\$ 79
Interest cost	43	43	129	130
Expected return on plan assets	(55)	(59)	(167)	(177)
Net amortization and deferral	6	6	20	18
Expense under accounting standards	23	16	69	50
Regulatory adjustment – deferred	(2)	—	(6)	—
<b>Total expense recognized</b>	<b>\$ 21</b>	<b>\$ 16</b>	<b>\$ 63</b>	<b>\$ 50</b>

##### *Postretirement Benefits Other Than Pensions*

Edison International previously disclosed in Note 7 of "Notes to Consolidated Financial Statements" included in Edison International's 2004 Annual Report that it expects to contribute approximately \$77 million to its postretirement benefits other than pensions plans in 2005. As of September 30, 2005, \$19 million in contributions have been made. Edison International anticipates that its original expectation will be met by year-end 2005.

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Expense components are:

In millions	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
			(Unaudited)	
Service cost	\$ 12	\$ 9	\$ 36	\$ 32
Interest cost	31	29	93	96
Expected return on plan assets	(26)	(27)	(77)	(82)
Amortization of unrecognized prior service costs	(7)	(8)	(22)	(24)
Amortization of unrecognized loss	12	7	36	38
<b>Total expense</b>	<b>\$ 22</b>	<b>\$ 10</b>	<b>\$ 66</b>	<b>\$ 60</b>

#### Note 4. 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.

#### *Aircraft Leases*

Edison Capital has invested in three aircraft leased to American Airlines. American has reported very large operating and net losses due to reduced pricing power, increases in capacity in excess of demand, deeply discounted fare sales and significant increases in fuel prices. In the event American Airlines defaults in making its lease payments, the lenders with a security interest in the aircraft or leases may exercise remedies that could lead to a loss of some or all of Edison Capital's investment in the aircraft plus any accrued interest. The total maximum loss exposure to Edison Capital in 2005 is \$39 million. A restructuring of the lease could also result in a loss of some or all of the investment. At September 30, 2005, American Airlines was current in its lease payments to Edison Capital.

#### *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

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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.

Edison International's recorded estimated minimum liability to remediate its 29 identified sites at SCE (22 sites) and EME (7 sites related to Midwest Generation) is \$84 million, \$81 million of which is related to SCE. 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 \$115 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 33 immaterial sites whose total liability ranges from \$4 million (the recorded minimum liability) to \$10 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing \$29 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of \$55 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.

Edison International 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 \$25 million. Recorded costs for the twelve months ended September 30, 2005 were \$11 million.

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 Income Taxes***

Edison International has reached a settlement with the IRS on tax issues and pending affirmative claims relating to its 1991–1993 tax years. This settlement, which was signed by Edison International in March 2005 and approved by the United States Congress Joint Committee on Taxation on July 27, 2005, resulted in a third quarter 2005 net earnings benefit for Edison International of approximately

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\$65 million, including interest, most of which relates to SCE. This benefit was reflected in the income statement caption "Income tax (benefit)."

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994–1996 and 1997–1999 tax years, respectively. Many of the asserted tax deficiencies are timing differences and, therefore, amounts ultimately paid (exclusive of interest and penalties), if any, would be deductible on future tax returns of Edison International.

As part of a nationwide challenge of certain types of lease transactions, the IRS has raised issues about the deferral of income taxes in audits of the 1994–1996 and 1997–1999 tax years associated with Edison Capital's cross-border leases. The IRS is challenging Edison Capital's foreign power plant and electric locomotive sale/leaseback transactions (termed a sale-in/lease-out or SILO transaction). The estimated federal and state taxes deferred from these leases were \$44 million in the 1994–1996 and 1997–1999 audit periods and \$32 million in subsequent years through 2004.

The IRS is also challenging Edison Capital's foreign power plant and electric transmission system lease/leaseback transactions (termed a lease-in, lease-out or LILO transaction). The estimated federal and state income taxes deferred from these leases were \$558 million in the 1997–1999 audit period and \$565 million in subsequent years through 2004. The IRS has also proposed interest and penalties in its challenge to each SILO and LILO transaction.

Edison International believes it properly reported these transactions based on applicable statutes, regulations and case law in effect at the time the transactions were entered into. Written protests were filed to appeal the 1994–1996 audit adjustments asserting that the IRS's position misstates material facts, misapplies the law and is incorrect. This matter is now being considered by the Administrative Appeals branch of the IRS. Edison International also filed protests in March 2005 to appeal the issues raised in the 1997–1999 audit.

Edison Capital also entered into a lease/service contract transaction in 1999 involving a foreign telecommunication system (termed a Service Contract). The IRS did not assert an adjustment for this lease in the 1997–1999 audit cycle but is expected to challenge this lease in subsequent audit cycles similar to positions asserted against the SILOs discussed above. The estimated federal and state taxes deferred from this lease are \$221 million through 2004.

If Edison International is not successful in its defense of the tax treatment for the SILOs, LILOs and the Service Contract, the payment of taxes, exclusive of any interest or penalties, would not affect results of operations under current accounting standards, although it could have a significant impact on cash flow. However, the FASB is currently considering changes to the accounting for leases. If the proposed accounting changes are adopted and Edison International's tax treatment for the SILOs, LILOs and Service Contract is significantly altered as a result of IRS challenges, there could be a material effect on reported earnings by requiring Edison International to reverse earnings previously recognized as a current period adjustment and to report these earnings over the remaining life of the leases. At this time, Edison International is unable to predict the impact of the ultimate resolution of these matters.

The IRS Revenue Agent Report for the 1997–1999 audit also asserted deficiencies with respect to a transaction entered into by an SCE subsidiary which may be considered substantially similar to a listed transaction described by the IRS as a contingent liability company. While Edison International intends to defend its tax return position with respect to this transaction, the tax benefits relating to the capital loss

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deductions will not be claimed for financial accounting and reporting purposes until and unless these tax losses are sustained.

In April 2004, Edison International filed California Franchise Tax amended returns for tax years 1997 through 2002 to abate the possible imposition of new California penalty provisions on transactions that may be considered as listed or substantially similar to listed transactions described in an IRS notice that was published in 2001. These transactions include certain Edison Capital leveraged lease transactions and the SCE subsidiary contingent liability company transaction described above. Edison International filed these amended returns under protest retaining its appeal rights.

#### *Investigations Regarding Performance Incentives Rewards*

SCE is eligible under its CPUC-approved performance-based ratemaking (PBR) mechanism to earn rewards or penalties for the period of 1997 through 2003 based on its performance in comparison to CPUC-approved standards of customer satisfaction, employee injury and illness reporting, and system reliability. Current CPUC ratemaking (through SCE's 2003 GRC decision) provides for performance incentives or penalties for differences between actual results and GRC-determined standards of employee injury and illness reporting, and system reliability.

SCE has been conducting investigations into its performance under these mechanisms and has reported to the CPUC certain findings of misconduct and misreporting as further discussed below. As a result of the reported events, the CPUC could institute its own proceedings to determine whether and in what amounts to order refunds or disallowances of past and potential PBR rewards for customer satisfaction, injury and illness reporting, and system reliability portions of PBR. The CPUC also may consider whether to impose additional penalties on SCE. SCE cannot predict with certainty the outcome of these matters or estimate the potential amount of refunds, disallowances, and penalties that may be required.

#### *Customer Satisfaction*

SCE received two letters in 2003 from one or more anonymous employees alleging that personnel in the service planning group of SCE's transmission and distribution business unit altered or omitted data in attempts to influence the outcome of customer satisfaction surveys conducted by an independent survey organization. The results of these surveys are used, along with other factors, to determine the amounts of any incentive rewards or penalties to SCE under the PBR provisions for customer satisfaction. SCE recorded aggregate customer satisfaction rewards of \$28 million for the years 1998, 1999 and 2000. Potential customer satisfaction rewards aggregating \$10 million for the years 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also anticipated that it could be eligible for customer satisfaction rewards of about \$10 million for 2003.

SCE has been keeping the CPUC informed of the progress of SCE's internal investigation. On June 25, 2004, SCE submitted to the CPUC a PBR customer satisfaction investigation report, which concluded that employees in the design organization of the transmission and distribution business unit deliberately altered customer contact information in order to affect the results of customer satisfaction surveys. At least 36 design organization personnel engaged in deliberate misconduct including alteration of customer information before the data were transmitted to the independent survey company. Because of the apparent scope of the misconduct, SCE proposed to refund to ratepayers \$7 million of the PBR rewards previously received and forego an additional \$5 million of the PBR rewards pending that are both attributable to the design organization's portion of the customer satisfaction rewards for the entire PBR period (1997–2003). In addition, during its investigation, SCE determined that it could not confirm the

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integrity of the method used for obtaining customer satisfaction survey data for meter reading. Thus, SCE also proposed to refund all of the approximately \$2 million of customer satisfaction rewards associated with meter reading. As a result of these findings, SCE accrued a \$9 million charge in 2004 for the potential refunds of rewards that have been received.

SCE has taken remedial action as to the customer satisfaction survey misconduct by severing the employment of several supervisory personnel, updating system process and related documentation for survey reporting, and implementing additional supervisory controls over data collection and processing. The PBR performance incentive mechanism for customer satisfaction expired after calendar year 2003 pursuant to the CPUC's decision in SCE's 2003 GRC.

The CPUC has not yet opened a formal investigative proceeding into this matter. However, the CPSD of the CPUC has submitted several data requests to SCE and has requested an opportunity to interview a number of current and former SCE employees in the design organization. SCE has responded to these requests and the CPSD has conducted interviews of approximately 20 employees who were disciplined for misconduct. In addition, the CPSD has conducted interviews of four senior managers and executives of the Transmission and Distribution Business Unit regarding the design organization.

#### *Employee Injury and Illness Reporting*

In light of the problems uncovered with the customer satisfaction surveys, SCE conducted an investigation into the accuracy of SCE's employee injury and illness reporting. The yearly results of employee injury and illness reporting to the CPUC are used to determine the amount of the incentive reward or penalty to SCE under the PBR mechanism. Since the inception of PBR in 1997, SCE has received \$20 million in employee safety incentives for 1997 through 2000 and, based on SCE's records, would have been entitled to an additional \$15 million for 2001 through 2003 (\$5 million for each year).

On October 21, 2004, SCE reported to the CPUC and other appropriate regulatory agencies certain findings concerning SCE's performance under the PBR incentive mechanism for injury and illness reporting. Under the PBR mechanism, rewards and/or penalties for the years 1997 through 2003 were based upon a total incident rate, which included two equally weighted measures: Occupational Safety and Health Administration (OSHA) recordable incidents and first aid incidents. The major issue disclosed in the investigative findings to the CPUC was that SCE failed to implement an effective recordkeeping system sufficient to capture all required data for first aid incidents. SCE's investigation also found reporting inaccuracies for OSHA recordable incidents, but the impact of these inaccuracies did not have a material effect on the PBR mechanism.

As a result of these findings, SCE proposed to the CPUC that it not collect any reward under the PBR mechanism for any year before 2004, and it return to ratepayers the \$20 million it has already received. Therefore, SCE accrued a \$20 million charge in 2004 for the potential refund of these rewards. SCE has also proposed to withdraw the pending requests for rewards for the 2001–2002 time frames. SCE has not yet filed a request related to its performance for 2003 under the PBR mechanism.

SCE is taking other remedial action to address the issues identified, including revising its organizational structure and overall program for environmental, health and safety compliance. SCE also took disciplinary action against twenty-four individuals in several SCE business areas in early June 2005. SCE submitted a report on the results of its investigation to the CPUC on December 3, 2004.

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As with the customer satisfaction matter, the CPUC has not yet opened a formal investigative proceeding into this matter. However, the CPSD did submit several data requests to SCE to which SCE has responded.

#### *System Reliability*

In light of the problems uncovered with the PBR mechanisms discussed above, SCE has conducted an investigation into the PBR system reliability metric for the years 1997 through 2003. Since the inception of PBR payments in 1997, SCE has received \$8 million in rewards and has applied for an additional \$5 million reward based on frequency of outage data for 2001. For 2002, SCE's data indicates that it earned no reward and incurred no penalty. Based on the application of the PBR mechanism, SCE would be penalized \$5 million for 2003; however, as indicated above, SCE has not filed a request related to its performance under the PBR mechanism for 2003.

On February 28, 2005, SCE provided its investigatory report on the PBR system reliability incentive mechanism to the CPUC concluding that the reliability reporting system is working as intended.

The CPUC is not expected to act on SCE's recent advice letter for 2004 or the pending PBR advice letters for 2001 and 2002 until the CPSD has completed its investigation of these matters. SCE has agreed to file its PBR advice letter for 2003 after the CPSD has completed its investigation.

#### *Navajo Nation Litigation*

In June 1999, the Navajo Nation filed a complaint in the United States District Court for the District of Columbia (D.C. District Court) against Peabody Holding Company (Peabody) and certain of its affiliates, Salt River Project Agricultural Improvement and Power District, and SCE arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal Racketeer Influenced and Corrupt Organizations statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentation 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, as well as a declaration that Peabody's lease and contract rights to mine coal on Navajo Nation lands should be terminated. SCE joined Peabody's motion to strike the Navajo Nation's complaint. In addition, SCE and other defendants filed motions to dismiss. The D.C. District Court denied these motions for dismissal, except for Salt River Project Agricultural Improvement and Power District's motion for its separate dismissal from the lawsuit.

Certain issues related to this case were addressed by the United States Supreme Court in a separate legal proceeding filed by the Navajo Nation in the United States Court of Federal Claims against the United States Department of Interior. In that action, the Navajo Nation claimed that the Government breached its fiduciary duty concerning negotiations relating to the coal lease involved in the Navajo Nation's lawsuit against SCE and Peabody. On March 4, 2003, the Supreme Court concluded, by majority decision, that there was no breach of a fiduciary duty and that the Navajo Nation did not have a right to relief against the Government. Based on the Supreme Court's analysis, on April 28, 2003, SCE and Peabody filed motions to dismiss or, in the alternative, for summary judgment in the D.C. District Court action. On April 13, 2004, the D.C. District Court denied SCE's and Peabody's April 2003 motions to dismiss or, in the alternative, for summary judgment. The D.C. District Court subsequently issued a scheduling order that imposed a December 31, 2004 discovery cut-off. Pursuant to a joint request of the parties, the D.C. District Court granted a 120-day stay of the action to allow the parties to attempt to resolve, through facilitated negotiations, all issues

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associated with Mohave. Negotiations are ongoing and the stay has been continued until further order of the court. On July 28, 2005, the D.C. District Court issued an order removing the lawsuit from the Court's active docket.

The Court of Appeals for the Federal Circuit, acting on a suggestion on remand filed by the Navajo Nation, held in an October 24, 2003 decision that the Supreme Court's March 4, 2003 decision was focused on three specific statutes or regulations and therefore did not address the question of whether a network of other statutes, treaties and regulations imposed judicially enforceable fiduciary duties on the United States during the time period in question. The Government and the Navajo Nation both filed petitions for rehearing of the October 24, 2003 Federal Circuit decision. Both petitions were denied on March 9, 2004. On March 16, 2004, the Federal Circuit issued an order remanding the case against the Government to the Court of Federal Claims, which conducted a status conference on May 18, 2004. As a result of the status conference discussion, the Court of Federal Claims ordered the Navajo Nation and the Government to brief the remaining issues following remand (described below). The Navajo Nation's initial brief was filed in the remanded Court of Federal Claims matter on August 26, 2004, and the Government filed its responsive brief on December 10, 2004. The Navajo Nation subsequently obtained an extension of the due date for its reply brief while the Court of Federal Claims considered a motion to strike filed by the Government. Peabody's motion to intervene in the remanded Court of Federal Claims case as a party was denied. On February 24, 2005, the Court of Federal Claims denied the motion to strike filed by the Government, but authorized the Government to file a supplemental brief and appendix, which was filed by the Government on March 23, 2005. On April 25, 2005, the Navajo Nation filed its reply brief and also filed a motion to strike the Government's supplemental brief and all of the exhibits attached to that brief. Oral argument on the Navajo Nation's motion to strike took place at a hearing on September 28, 2005, at which time the motion was denied. At the same hearing, the Court of Federal Claims heard argument on the issues remanded by the Federal Circuit, which are focused on (1) whether the Navajo Nation previously waived its "network of other laws" argument and, (2) if not, whether the Navajo Nation can establish that the Government breached any fiduciary duties pursuant to such "network." At the conclusion of the September 28, 2005 hearing, the Court of Federal Claims took the remanded issues under submission.

SCE cannot predict with certainty the outcome of the 1999 Navajo Nation's complaint against SCE, the impact of the Supreme Court's decision in the Navajo Nation's suit against the Government on this complaint, or the impact of the complaint on the operation of Mohave beyond 2005.

#### *Nuclear Insurance*

Federal law limits public liability claims from a nuclear incident to \$10.8 billion. SCE and other owners of San Onofre Nuclear Generating Station 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 Nuclear Regulatory Commission exempted San Onofre Unit 1 from this secondary level, effective June 1994. The current maximum deferred premium for each nuclear incident is \$101 million per reactor, but not more than \$15 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 will be adjusted for inflation on a 5-year schedule. The next inflation adjustment will occur on August 31, 2008. Based on its ownership interests, SCE could be required to pay a maximum of \$199 million per nuclear incident. However, it would have to pay no more than \$30 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

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the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators. All licensed operating plants including San Onofre and Palo Verde are grandfathered under the applicable law.

Property damage insurance covers losses up to \$500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary \$500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. A mutual insurance company owned by utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to \$44 million per year. Insurance premiums are charged to operating expense.

#### *Schedule Coordinator Tariff Dispute*

SCE serves as an SC for the Los Angeles Department of Water & Power (DWP) over the ISO-controlled grid. In mid-2003, SCE filed a petition asking that the FERC accept a tariff that provides for a direct pass-through of the FERC-authorized charges incurred by SCE on the DWP's behalf. The DWP protested SCE's filing. The DWP asked the FERC to declare that SCE was obligated to serve as the DWP's SC without charge. In late 2003, the FERC accepted the tariff, subject to refund. The FERC held that the proposed tariff has not been shown to be just and reasonable.

In accordance with the terms of the tariff, SCE issued several invoices for charges to the DWP. The DWP has objected to all of the charges but has paid, under protest, approximately \$18 million. The DWP has protested specific charges totaling approximately \$5 million based on its allegations that those specific charges are improper for various reasons.

The FERC has not issued a final order on this issue. SCE could be required to refund all or part of the amounts collected under the tariff. SCE continues to invoice the DWP. Monthly invoices have been averaging approximately \$1 million. SCE cannot predict with certainty the outcome of the FERC final order.

#### *Spent Nuclear Fuel*

Under federal law, the United States Department of Energy (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 obligation to begin acceptance of spent nuclear fuel not later than 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 through April 6, 1983 (approximately \$24 million, plus interest). SCE is also paying the 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 DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre. The case is currently stayed pending development in other spent nuclear fuel cases also before the United States Court of Federal Claims.

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SCE has primary responsibility for the interim storage of spent nuclear fuel generated at San Onofre. Spent nuclear fuel is stored in the San Onofre Units 2 and 3 spent fuel pools and the San Onofre independent spent fuel storage installation. Movement of Unit 1 spent fuel from the Unit 2 spent fuel pool to the independent spent fuel storage installation is complete. There is now sufficient space in the Unit 2 and 3 spent fuel pools to meet plant requirements through mid-2007 and mid-2008, respectively. In order to maintain a full core off-load capability, SCE is planning to begin moving Unit 2 and 3 spent fuel into the independent spent fuel storage installation by late 2006.

In order to increase on-site storage capacity and maintain core off-load capability, Palo Verde has constructed a dry cask storage facility. Arizona Public Service, as operating agent, plans to continually load casks on a schedule to maintain full core off-load capability for all three units.

#### Note 5. Business Segments

Edison International's reportable business segments include an electric utility operation segment (SCE), a nonutility power generation segment (MEHC – parent only and EME), and a financial services provider segment (Edison Capital). Also, in accordance with an accounting standard related to the impairment and disposal of long-lived assets, prior periods have been restated to reflect EME's international operations being reported as discontinued operations.

Segment information for the three and nine months ended September 30, 2005 and 2004 was:

In millions	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2005	2004	2005	2004
	(Unaudited)			
<b>Operating Revenue:</b>				
Electric utility	\$ 3,084	\$2,655	\$7,194	\$ 6,527
Nonutility power generation	677	509	1,605	1,257
Financial services	21	22	72	78
Corporate and other	1	2	7	7
<b>Consolidated Edison International</b>	<b>\$ 3,783</b>	<b>\$3,188</b>	<b>\$8,878</b>	<b>\$ 7,869</b>
<b>Net Income (Loss):</b>				
Electric utility <sup>(1)</sup>	\$ 280	\$ 259	\$ 572	\$ 600
Nonutility power generation <sup>(2)</sup>	181	559	234	(44)
Financial services <sup>(3)</sup>	3	12	80	33
Corporate and other	(2)	(17)	(22)	(52)
<b>Consolidated Edison International</b>	<b>\$ 462</b>	<b>\$ 813</b>	<b>\$ 864</b>	<b>\$ 537</b>

(1) Net income available for common stock.

(2) Includes earnings from discontinued operations of \$27 million and \$55 million, respectively, for the three and nine months ended September 30, 2005 and \$499 million and \$570 million, respectively, for the three and nine months ended September 30, 2004.

(3) Includes a loss of \$1 million from the cumulative effect of an accounting change for the nine months ended September 30, 2004.

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Corporate and other includes amounts from nonutility subsidiaries not significant as a reportable segment.

Total segment assets as of September 30, 2005 were: electric utility, \$25 billion; nonutility power generation, \$7 billion; and, financial services, \$4 billion.

#### **Note 6. Agreement to Sell the Doga Project**

EME owns an 80% interest in a 180-MW gas-fired cogeneration plant near Istanbul, Turkey, which EME refers to as the Doga project. On August 17, 2005, EME entered into a purchase agreement, to sell its interest in the Doga project to EME's co-investor in the Doga project, Doga Enerji Yatirim Isletme ve Ticaret Limited Sirketi, which will acquire an additional 30% interest in the Doga project, and The Kansai Electric Power Co., Inc., which will acquire a 50% interest in the Doga project. Completion of the sale is subject to the satisfaction of a number of closing conditions, including obtaining the consent of a majority of the project's lenders. The sale is expected to close in the fourth quarter of 2005.

#### **Note 7. Discontinued Operations**

On February 3, 2005, EME sold its 25% equity interest in the Tri Energy project, pursuant to a purchase agreement dated December 15, 2004, to a consortium comprised of International Power plc (70%) and Mitsui & Co., Ltd. (30%), referred to as IPM, for approximately \$20 million. The sale of this investment had no significant effect on net income in the first quarter of 2005.

On January 10, 2005, EME sold its 50% equity interest in the Caliraya-Botocan-Kalayaan project to Corporacion IMPSA S.A., pursuant to a purchase agreement dated November 5, 2004. Proceeds from the sale were approximately \$104 million. EME recorded a pre-tax gain on the sale of approximately \$9 million during the first quarter of 2005.

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

On September 30, 2004, EME sold its 51% interest in Contact Energy to Origin Energy New Zealand Limited pursuant to a purchase agreement dated July 20, 2004. The purchase agreement was entered into following a competitive bidding process. Consideration for the sale was NZ\$1.6 billion (approximately \$1.1 billion) which includes NZ\$535 million of debt assumed by the purchaser. EME recorded an after-tax gain on sale of \$141 million during the third quarter of 2004.

EME previously owned and operated a 220-MW combined cycle, natural gas-fired power plant located in the United Kingdom, known as the Lakeland project. The ownership of the project was held through EME's indirect subsidiary, Lakeland Power Ltd., which sold power generated from the plant pursuant to a power sales agreement with Norweb Energi Ltd., a subsidiary of TXU (UK) Holdings Limited (TXU UK) and an indirect subsidiary of TXU Europe Group plc (TXU Europe). EME ceased consolidating the activities of Lakeland Power Ltd. in 2002, when an administrative receiver was appointed following a default by Norweb Energi Ltd. under the power sales agreement. Accordingly, EME accounts for its ownership of Lakeland Power Ltd. on the cost method and earnings are recognized as cash is distributed from this entity.

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As previously disclosed, the administrative receiver of Lakeland Power Ltd. filed a claim against Norweb Energi Ltd. for termination of the power sales agreement. On November 19, 2002, TXU UK and TXU Europe, together with a related entity, TXU Europe Energy Trading Limited, entered into formal administration proceedings of their own in the United Kingdom (similar to bankruptcy proceedings in the United States). On March 31, 2005, Lakeland Power Ltd. received £112 million (approximately \$210 million) from the TXU administrators, representing an interim payment of 97% of its accepted claim of £116 million (approximately \$217 million).

From the amount received, Lakeland Power Ltd., now controlled by a liquidator in the United Kingdom, has made a payment of £20 million (approximately \$37 million) to EME on April 7, 2005 comprised of £7 million (approximately \$13 million) for a secured loan which EME purchased from Lakeland Power Ltd.'s secured creditors in 2004 and certain unsecured receivables from Lakeland Power Ltd., and £13 million (approximately \$24 million) as a distribution to the EME subsidiary that owns the equity interest in Lakeland Power Ltd. This distribution was recognized in income during the quarter ended June 30, 2005. Additionally, Lakeland Power Ltd. will pay to EME's subsidiary that owns the equity interest in Lakeland Power Ltd. the amount remaining after resolution of any remaining secured and unsecured creditor claims and payment of or provision for tax liabilities and the fees and expenses associated with Lakeland Power Ltd.'s liquidation.

EME estimates that the remaining net proceeds after tax (including taxes due in the United States) and net income resulting from the above payments will be approximately \$64 million. The majority of the remaining proceeds are expected to be received in 2006, when Lakeland Power Ltd.'s liquidation is expected to be completed. Because the amounts required to settle outstanding claims and UK taxes have not been finalized and cannot be estimated precisely in the context of the liquidation, the actual amount of net proceeds and increase in net income may vary materially from the above estimate.

For all periods presented, the results of EME's international projects, except for the Doga project (see Note 6), discussed above have been accounted for as discontinued operations in the consolidated financial statements in accordance with an accounting standard related to the impairment and disposal of long-lived assets.

There was no revenue from discontinued operations in 2005. For the three and nine months ended September 30, 2004, revenue from discontinued operations was \$354 million and \$1.1 billion, respectively. For the three months ended September 30, 2005 and 2004, pre-tax income (loss) was \$(2) million and \$41 million, respectively. For the nine months ended September 30, 2005 and 2004, pre-tax income was \$20 million and \$165 million, respectively.

During the third quarter ended September 30, 2005, EME recorded tax adjustments of \$28 million, which resulted from the completion of the 2004 federal and California income tax returns and quarterly review of tax accruals. The majority of the tax adjustments are related to the sale of the international assets. These adjustments (benefits) are included in income from discontinued operations – net of tax on the consolidated income statements. During the quarter ended September 30, 2004, EME recorded a deferred income tax benefit of \$327 million to recognize the higher tax basis of its international holding company over its book basis as required by accounting rules applicable to discontinued operations.

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The carrying value of assets and liabilities recorded as discontinued operations is:

In millions	September 30, 2005	December 31, 2004
	(Unaudited)	
<b>Assets</b>		
Cash and equivalents	\$ 2	\$ 2
Other current assets	—	2
<b>Total current assets</b>	<b>2</b>	<b>4</b>
Investments in partnerships and unconsolidated subsidiaries	—	107
Other deferred charges	10	11
<b>Total assets of discontinued operations</b>	<b>\$ 12</b>	<b>\$ 122</b>
<b>Liabilities</b>		
Accounts payable and accrued liabilities	\$ —	\$ 2
<b>Total current liabilities</b>	<b>—</b>	<b>2</b>
Customer advances and other deferred credits	5	4
Other long-term liabilities	10	9
<b>Total liabilities of discontinued operations</b>	<b>\$ 15</b>	<b>\$ 15</b>

#### Note 8. Impairment Losses and Loss on Lease Termination

##### *Impairment Loss on Equity Method Investment*

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

##### *Asset Impairment*

In September 2004, EME completed an analysis of future competitiveness in the expanded PJM Interconnection, LLC marketplace of its eight remaining small peaking units in Illinois. Based on this analysis, EME decided to decommission six of the eight small peaking units. As a result of the decision to decommission the units, projected cash flows associated with the Illinois peaking units were less than the book value of the units resulting in an impairment under an accounting standard for the impairment or disposal of long-lived assets. During the third quarter of 2004, EME recorded a pre-tax impairment charge of \$29 million (approximately \$18 million after tax).

## **EDISON INTERNATIONAL**

### **NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

#### ***Loss on Lease Termination***

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

#### **Note 9. Commitments**

The following is an update to Edison International's commitments. See Note 9 of "Notes to Consolidated Financial Statements" included in Edison International's 2004 Annual Report for a detailed discussion.

#### ***Leases***

During the first quarter of 2005, SCE entered into new power contracts in which it takes virtually all of the power. In accordance with an accounting standard, these power contracts are classified as operating leases. SCE's commitments under these operating leases are currently estimated to be \$39 million for 2005, \$55 million for 2006, \$50 million for 2007 and \$43 million for 2008.

#### ***Other Commitments***

Midwest Generation, LLC (Midwest Generation) and EME Homer City Generation L.P. (EME Homer City) have entered into additional fuel purchase commitments with various third-party suppliers during the first nine months of 2005. These additional commitments are currently estimated to be \$22 million for 2005, \$114 million for 2006, \$169 million for 2007, \$44 million for 2008, and \$62 million for 2009.

Midwest Generation has contractual agreements for the transport of coal to its facilities. The primary contract is with Union Pacific Railroad (and various delivering carriers) which extend through 2011. Midwest Generation commitments under this agreement are based on actual coal purchases from the Powder River Basin. Accordingly, contractual obligations for transportation are based on coal volumes set forth in fuel supply contracts. The increase in transportation commitments entered into during the first nine months of 2005 relates to additional volumes of fuel purchases using the terms of existing transportation agreements. These commitments are currently estimated to be \$33 million for 2005, \$61 million for 2006, \$117 million for 2007, \$40 million for 2008, and \$77 million for 2009.

During the first quarter of 2005, SCE entered into additional power call option contracts. SCE's revised purchased-power capacity payment commitments under these contracts are currently estimated to be \$31 million for 2005, \$95 million for 2006, \$101 million for 2007 and \$84 million for 2008.

#### ***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.

## EDISON INTERNATIONAL

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

#### *EME's Tax Indemnity Agreements*

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

#### *Indemnities Provided as Part of EME's Acquisition of the Illinois Plants*

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

Midwest Generation entered into a supplemental agreement with Commonwealth Edison and Exelon Generation Company 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 existing asbestos claims and expenses less recovery of insurance costs, and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement. As a general matter, Commonwealth Edison and Midwest Generation apportion responsibility for future asbestos-related claims based upon the number of exposure sites that are Commonwealth Edison locations or Midwest Generation locations. The obligations under this agreement are not subject to a maximum liability. The supplemental agreement has a five-year term with an automatic renewal provision (subject to the right of either party to terminate). Payments are made under this indemnity upon tender by Commonwealth Edison of appropriate proof of liability for an asbestos-related settlement, judgment, verdict, or expense. There were between 170 and 190 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed at September 30, 2005. Midwest Generation had recorded a \$68 million liability at September 30, 2005 related to this matter.

The amounts recorded by Midwest Generation for the asbestos-related liability are based upon a number of assumptions. Projecting 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.

## EDISON INTERNATIONAL

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

#### *Indemnity Provided as Part of EME's 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 as specified in the Asset Purchase Agreement dated August 1, 1998. 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. Payments would be triggered under this indemnity by a claim from the sellers. EME has not recorded a liability related to this indemnity.

#### *Indemnities Provided under EME's 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. EME also provided an indemnity to IPM for matters arising out of the exercise by one of its project partners of a purported right of first refusal. 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 September 30, 2005, EME had recorded an \$86 million 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. EME has not recorded a liability related to these indemnities.

#### *Guarantee of Brooklyn Navy Yard Contractor Settlement Payments*

On March 31, 2004, EME completed the sale of 100% of the stock of Mission Energy New York, Inc., which holds a 50% partnership interest in Brooklyn Navy Yard Cogeneration Partners, L.P. (referred to as Brooklyn Navy Yard), to BNY Power Partners LLC. Brooklyn Navy Yard owns a 286-MW gas-fired cogeneration power plant in Brooklyn, New York. In February 1997, the construction contractor asserted general monetary claims under the turnkey agreement against Brooklyn Navy Yard. A settlement agreement was executed on January 17, 2003, and all litigation has been dismissed. EME agreed to indemnify Brooklyn Navy Yard and, in connection with the sale of EME's interest in Brooklyn Navy Yard, BNY Power Partners for any payments due under this settlement agreement, which are scheduled through January 2007. At September 30, 2005, EME had recorded a \$7 million liability related to this indemnity.

#### *EME's Capacity Indemnification Agreements*

EME has guaranteed, jointly and severally with Texaco Inc., the obligations of March Point Cogeneration Company under its project power sales agreements to repay capacity payments to the project's power purchaser in the event that the power sales agreements terminate, March Point Cogeneration Company abandons the project, or the project fails to return to normal operations within a reasonable time after a complete or partial shutdown, during the term of the power contracts. In addition, a subsidiary of EME has guaranteed the obligations of Sycamore Cogeneration Company under its project power sales agreement to repay capacity payments to the project's power purchaser in the event that the project

## EDISON INTERNATIONAL

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

unilaterally terminates its performance or reduces its electric power producing capability during the term of the power contract. The obligations under the indemnification agreements as of September 30, 2005, if payment were required, would be \$134 million. EME has not recorded a liability related to this indemnity.

#### *Indemnity Provided as Part of SCE's 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. The generating station has not operated since early 2001, and 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.

#### **Note 10. Preferred Stock Subject to Mandatory Redemption**

SCE redeemed 807,000 shares of 7.23% \$100 cumulative preferred stock at par value on April 30, 2005 and 637,500 shares of 6.05% \$100 cumulative preferred stock at par value on May 20, 2005.

#### **Note 11. Preferred and Preference Stock of Utility Not Subject to Mandatory Redemption**

SCE's authorized shares are: \$100 cumulative preferred – 12 million; \$25 cumulative preferred – 24 million and preference – 50 million. SCE issued 4 million shares of 5.349% Series A preference stock (non-cumulative, \$100 liquidation value) on April 27, 2005. The Series A preference stock may not be redeemed prior to April 30, 2010. After April 30, 2010, SCE may, at its option, redeem the shares in whole or in part and the dividend rate may be adjusted. SCE issued 2 million shares of 6.125% Series B preference stock (non-cumulative, \$100 liquidation value) on September 21, 2005. The Series B preference stock may not be redeemed prior to September 30, 2010. After September 30, 2010, SCE may, at its option, redeem the shares in whole or in part. There is no sinking fund for the redemption or repurchase of the shares. The Series A and B preference stock rank junior to all of the preferred stock and senior to all common stock. The Series A and B preference stock is not convertible into shares of any other class or series of SCE's capital stock or any other security. Shares of SCE's preferred stock have liquidation and dividend preferences over shares of SCE's preference stock and common stock.

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

### **INTRODUCTION**

This Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) for the three- and nine-month periods ended September 30, 2005 discusses material changes in the financial condition, results of operations and other developments of Edison International since December 31, 2004, and as compared to the three- and nine-month periods ended September 30, 2004. This discussion presumes that the reader has read or has access to Edison International's MD&A for the calendar year 2004 (the year-ended 2004 MD&A), which was included in Edison International's 2004 annual report to shareholders and incorporated by reference into Edison International's Annual Report on Form 10-K for the year ended December 31, 2004, 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 ability of Edison International to meet its financial obligations and to pay dividends on its common stock if its subsidiaries are unable to pay dividends;
- the ability of Southern California Edison Company (SCE) to recover its costs in a timely manner from its customers through regulated rates;
- decisions and other actions by the California Public Utilities Commission (CPUC) and other regulatory authorities and delays in regulatory actions;
- market risks affecting SCE's energy procurement activities;
- access to capital markets and the cost of capital;
- changes in interest rates and rates of inflation;
- governmental, statutory, regulatory or administrative changes or initiatives affecting the electricity industry, including the market structure rules applicable to each market and environmental regulations 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, equipment failure, availability, heat rate and output;
- the availability of labor, equipment and materials;
- the ability to obtain sufficient insurance;
- effects of legal proceedings, changes in tax laws, rates or policies, and changes in accounting standards;
- supply and demand for electric capacity and energy, and the resulting prices and dispatch volumes, in the wholesale markets to which Edison Mission Energy's (EME) generating units have access;
- the cost and availability of coal, natural gas, and fuel oil, and associated transportation costs;
- the cost and availability of emission credits or allowances for emission credits for EME and its subsidiaries;

- transmission congestion in and to each market area and the resulting differences in prices between delivery points in which EME and its subsidiaries operate;
- the ability to provide sufficient collateral in support of hedging activities and purchases of fuel and electric energy;
- 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, including new plants and technologies that may be developed in the future;
- general political, economic and business conditions;
- weather conditions, natural disasters and other unforeseen events; and
- changes in the fair value of investments accounted for using fair value accounting.

Additional information about risks and uncertainties, including more detail about the factors described above, is contained throughout this MD&A. 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. The information contained in this report is subject to change without notice. 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 and Exchange Commission. The following discussion provides updated information about material developments since the issuance of the year-ended 2004 MD&A and should be read in conjunction with the financial statements contained in this quarterly report and Edison International's Annual Report on Form 10-K for the year ended December 31, 2004.

Edison International is engaged in the business of holding, for investment, the common stock of its subsidiaries. Edison International's principal operating subsidiaries are Southern California Edison Company (SCE), Edison Mission Energy (EME) and Edison Capital. Mission Energy Holding Company (MEHC) (parent), a subsidiary of Edison International, is the holding company for its wholly owned subsidiary EME. Since the second quarter of 2004, MEHC (parent) and EME are presented as one business segment on a consolidated basis. SCE comprises the largest portion of the assets and revenue of Edison International. In this MD&A, except when stated to the contrary, references to each of Edison International, SCE, MEHC, EME or Edison Capital mean each such company with its subsidiaries on a consolidated basis. References to Edison International (parent) or parent company and MEHC (parent) mean Edison International or MEHC on a stand-alone basis, not consolidated with its subsidiaries. References to SCE, EME or Edison Capital followed by "(stand alone)" mean each such company alone, not consolidated with its subsidiaries.

This MD&A is presented in 10 major sections. The MD&A begins with a discussion of current developments. Following is a company-by-company discussion of Edison International's principal business segments (SCE, MEHC, and Edison Capital) and Edison International (parent). Each principal business segment's discussion 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, including results of operations and historical cash flow analysis, discontinued operations, new and proposed accounting principles, commitments, guarantees and indemnities and other developments. These sections should be read in conjunction with the continuing operations discussion of each principal business segment's section.

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## **CURRENT DEVELOPMENTS**

The following section provides a summary of current developments related to Edison International's principal business segments. This section is intended to be a summary of those current developments that management believes are of most importance since year-end December 31, 2004. This section is not intended to be an all-inclusive list of all current developments related to each principal business segment. Further details of each current development discussed below can be found in the specific principal business segment's section of this MD&A, along with discussions of liquidity, market risk exposures, and other matters as relevant to each principal business segment.

### **Passage of Comprehensive Energy Legislation by Congress**

A comprehensive energy bill was passed by the House and Senate in July 2005 and was signed by the President on August 8, 2005. Known as "EPAct 2005," this comprehensive legislation includes provisions for the repeal of the Public Utility Holding Company Act (PUHCA), for amendments to the Public Utility Regulatory Policies Act of 1978 (PURPA), for the introduction of new regulations regarding "Transmission Operation Improvements," for Transmission Rate Reform, for incentives for various generation technologies and for the extension through December 31, 2007 of production tax credits for wind and other specified types of generation. A number of these provisions will require implementing regulations to be promulgated by the Federal Energy Regulatory Commission (FERC). Edison International is currently assessing the potential impact of this legislation and the likely regulations.

## **SCE: CURRENT DEVELOPMENTS**

### **2006 General Rate Case Proceeding**

On December 21, 2004, SCE filed its application for a 2006 General Rate Case (GRC) requesting a 2006 base rate revenue requirement of \$4.06 billion, an increase of \$370 million over SCE's 2005 base rate revenue. The increase is primarily for capital-related expenditures to accommodate infrastructure replacement, and customer and load growth. The requested increase is also necessary to fund substantially higher operating and maintenance (O&M) expenses, particularly in SCE's transmission and distribution business unit. SCE also requested that the CPUC authorize the continuation of SCE's existing post-test year rate-making mechanism.

As part of the GRC process, the CPUC's Office of Ratepayer Advocates (ORA) submitted testimony proposing adjustments to reduce SCE's requested 2006 base rate revenue requirement to \$3.55 billion. In addition, several intervenors have proposed further adjustments, totaling \$230 million, to reduce SCE's requested 2006 base rate revenue requirement.

During the course of the GRC proceeding, SCE agreed to certain revisions to its request, updated the revenue requirement for the 2005 cost of capital, and incorporated a second refueling and maintenance outage in the O&M expense forecast for San Onofre Nuclear Generating Station (San Onofre) in 2006. SCE's revised requested 2006 base rate revenue requirement is \$3.96 billion, an increase of \$325 million over SCE's 2005 base rate revenue. SCE also proposed revised base rate revenue increases of \$108 million for 2007 and \$113 million for 2008.

A final CPUC decision is expected in January 2006. SCE cannot predict with certainty the final outcome of SCE's GRC application. See "SCE: Regulatory Matters—Transmission and Distribution—2006 General Rate Case Proceeding" for further discussion.

## **MEHC: CURRENT DEVELOPMENTS**

### **EME Restructuring Activities**

During 2004, EME sold most of its international operations. EME's international operations, except for the Doga project, are accounted for as discontinued operations in accordance with an accounting standard for the impairment or disposal of long-lived assets, and, accordingly, all prior periods have been restated to reclassify the results of operations and assets and liabilities as discontinued operations. In the first quarter of 2005, EME completed the sale of two international projects:

- EME sold its 50% equity interest in the Caliraya-Botocan-Kalayaan (CBK) project to CBK Projects B.V., the purchasing entity designated by its partner, for \$104 million.
- EME sold its 25% equity interest in the Tri Energy project to IPM for approximately \$20 million.

EME entered into a purchase agreement, dated as of August 17, 2005, to sell its 80% interest in the Doga project to EME's co-investor in the Doga project, Doga Enerji Yatirim Isletme ve Ticaret Limited Sirketi, which will acquire an additional 30% interest in the Doga project, and The Kansai Electric Power Co., Inc., which will acquire a 50% interest in the Doga project. Completion of the sale is subject to the satisfaction of a number of closing conditions, including obtaining the consent of a majority of the project's lenders. The sale is expected to close in the fourth quarter of 2005.

In connection with the sale of its international operations in 2004, together with cash on hand, in January 2005, EME:

- made distributions to MEHC totaling \$360 million, which were subsequently used primarily to repay the remaining \$285 million portion of the term loan.
- repaid its junior subordinated debentures and, consequently, repaid the monthly income preferred securities (MIPS) totaling \$150 million.

In April 2005, EME made an equity contribution of \$300 million to Midwest Generation, which used the proceeds to repay indebtedness. See "MEHC: Liquidity—Midwest Generation Financing" for a discussion of the Midwest Generation financing.

EME has also completed a review of its domestic organization to better align its resources with its domestic business requirements. Management and organizational changes have been implemented to streamline EME's reporting relationships and eliminate its regional management structure. As a result of these changes, EME recorded charges of approximately \$10 million (pre-tax) in the nine months ended September 30, 2005 for severance and related costs.

### **Business Development Plans**

Following the completion of restructuring activities described above, EME, together with its affiliate, Edison Capital, has established a joint business development effort for wind projects in addition to EME's development plans for thermal projects.

#### *Wind Business Development*

EME's affiliate, Edison Capital, has an existing 196 megawatt (MW) portfolio of wind projects located in Iowa and Minnesota. In addition, a subsidiary of Edison Capital has entered into an agreement to acquire a 120 MW wind project in eastern New Mexico from a wind generation developer for \$157 million. The acquisition of this project is subject to achieving commercial operations and other closing conditions,

which are expected to be met in December 2005. EME and Edison Capital are considering transferring some or all of these projects to EME as part of EME's independent power generation portfolio and expanding significantly, through EME, further investments in wind projects throughout the United States. In addition, EME is considering entering into agreements to purchase wind turbines to support these wind business development activities. Pursuit of new renewable energy investments depends upon economic and regulatory conditions and may be affected by government policies supporting renewable energy. In August 2005, federal incentives for new wind projects, referred to as production tax credits, were extended for new wind projects installed by December 31, 2007 under a comprehensive federal energy bill, named the "Energy Policy Act of 2005."

#### *Thermal Business Development*

EME continues to review opportunities to develop or acquire additions to its power generation portfolio. As part of this activity, EME had begun the process of obtaining permits for two sites in Southern California for peaker plants and has responded to several requests for proposals to build or acquire generation. Pursuit of new thermal projects in California and elsewhere depends on a range of factors outside the control of EME, and, accordingly, there is no assurance that these efforts will result in the actual development or acquisition of additional generation capacity.

#### **Expiration of the Exelon Power Purchase Agreements**

The five-year power purchase agreements between Midwest Generation and Exelon Generation Company expired on December 31, 2004 and, accordingly, beginning January 1, 2005, all the output from the Illinois plants is considered merchant generation. In 2004, approximately 53% of the energy and capacity sales from the Illinois plants were to Exelon Generation under the power purchase agreements.

The Exelon Generation power purchase agreement for coal-fired units was structured to provide significant capacity payments and lower energy payments which were primarily designed to reimburse the cost of production. The agreement also provided for substantial capacity payments during the summer months. The Illinois plants continue to derive revenue from sales of capacity and energy. In the current wholesale energy market, energy prices are substantially higher than the energy prices previously set forth in the agreement, but capacity payments are, and are expected to remain for some time, substantially lower. As a result, the composition of EME's revenue was significantly different in the first nine months of 2005 compared to 2004. EME's merchant generation is subject to significant volatility as described further in "MEHC: Market Risk Exposures—Commodity Price Risk."

#### **Wholesale Energy Prices in Illinois**

Wholesale energy prices at the Northern Illinois Hub (related to the Illinois plants) have increased substantially in 2005 from the comparable market prices in 2004 driven largely by increases in the market price of natural gas and oil. The average market price during the nine months ended September 30, 2005 at the Northern Illinois Hub (related to the Illinois plants) increased to \$44.26 per MWh, compared to the average market prices "Into ComEd" and at the Northern Illinois Hub of \$29.36 per MWh during the nine months ended September 30, 2004.

#### **Energy Trading Activities**

EME seeks to generate profit by utilizing the commercial platform of its subsidiary, Edison Mission Marketing & Trading, to engage in trading activities in those markets in which it is active as a result of its management of the merchant power plants of Midwest Generation and Homer City. Edison Mission Marketing & Trading trades power, fuel and transmission primarily in the eastern power grid using products available over-the-counter, through exchanges and from independent system operators. Earnings from energy trading activities were \$84 million and \$125 million for the third quarter and nine months

ended September 30, 2005, respectively. Volatile market conditions during the first nine months of 2005, driven by increased prices for natural gas and oil and warmer summer temperatures, have created favorable conditions for Edison Mission Marketing & Trading's trading strategies in 2005 compared to 2004. This trading activity is limited by the risk management policies of EME, including a limit on value at risk. During the first nine months of 2005, the maximum value at risk associated with trading of over-the-counter products and exchange-traded products was \$1.9 million, using a 95% confidence interval and assuming a one-day holding period. As of September 30, 2005, the collateral required to support Edison Mission Marketing & Trading's transactions was approximately \$90 million. EME's management pays particular attention to the risk management of these activities, because income from them will vary substantially from period to period depending on market conditions.

### **Impairment Loss on Equity Method Investment**

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

## SOUTHERN CALIFORNIA EDISON COMPANY

### SCE: LIQUIDITY

SCE's liquidity is primarily affected by under- or over-collections of energy procurement-related costs, collateral requirements associated with power-purchase contracts, and access to capital markets or external financings. At September 30, 2005, SCE's credit and long-term senior secured issuer ratings from Standard & Poor's and Moody's Investors Service were BBB+ and A3, respectively. At September 30, 2005, SCE's short-term (commercial paper) credit ratings from Standard & Poor's and Moody's Investors Service were A2 and P2, respectively.

As of September 30, 2005, SCE had cash and equivalents of \$484 million (\$117 million of which was held by SCE's consolidated Variable Interest Entities (VIEs)). As of September 30, 2005, long-term debt, including current maturities of long-term debt, was \$5.34 billion. In February 2005, SCE replaced its \$700 million credit facility with a \$1.25 billion senior secured 5-year revolving credit facility. The security pledged (first and refunding mortgage bonds) for the new facility can be removed at SCE's discretion. If SCE chooses to remove the security, the credit facility's rating and pricing will change to an unsecured basis per the terms of the credit facility agreement. As of September 30, 2005, SCE's credit facility supported \$12 million in letters of credit, leaving \$1.24 billion available under the credit facility.

As discussed in "SCE: Regulatory Matters—Generation and Power Procurement—Energy Resource Recovery Account Proceedings," the CPUC established the Energy Resource Recovery Account (ERRA) as the rate-mechanism to track and recover energy procurement-related costs. As of September 30, 2005, the ERRA was overcollected by \$112 million.

SCE has entered into margining agreements for power and gas trading activities to support the risk of nonperformance. SCE's margin deposit requirements can vary depending upon the level of unsecured credit extended by counterparties and brokers, the California Independent System Operator (ISO) credit requirements, changes in market prices relative to contractual commitments, and other factors. At September 30, 2005, SCE had deposited \$130 million in cash with a broker in margin accounts in support of gas trading activities and had deposited \$31 million (comprised of \$19 million in cash and \$12 million in letters of credit) with counterparties in support of power-purchase agreements and to enter into transactions for imbalance energy through the ISO. Deposits with counterparties and brokers earn interest at various rates. The \$149 million of cash deposited with brokers and counterparties are reflected in the caption "Margin and Collateral Deposits" on the balance sheet.

SCE's estimated cash outflows, during the twelve-month period following September 30, 2005, consist of:

- Debt maturities of approximately \$597 million, including approximately \$247 million of rate reduction notes that are due at various times in 2005 and 2006, but which have a separate cost recovery mechanism approved by state legislation and CPUC decisions;
- Projected capital expenditures primarily to replace and expand distribution and transmission infrastructure and construct and replace generation assets, as discussed below;
- Dividend payments to SCE's parent company. SCE made a \$71 million dividend payment to Edison International on each of April 28, 2005, July 28, 2005 and September 30, 2005;

- Fuel and procurement-related costs; and
- General operating expenses.

SCE expects to meet its continuing obligations, including cash outflows for power-procurement undercollections (as incurred), through cash and equivalents on hand, operating cash flows and short-term borrowings, when necessary. Projected capital expenditures are expected to be financed through operating cash flows and the issuance of long-term debt and preferred equity.

SCE is experiencing significant growth in actual and planned capital expenditures to replace and expand its distribution and transmission infrastructure, and to construct and replace generation assets. In April 2005, the Finance Committee of SCE's Board of Directors approved a \$10.1 billion capital budget and forecast for the period 2005–2009, an increase of approximately \$700 million over the \$9.4 billion amount adopted in October 2004. The increase is mainly due to acceleration of spending in 2005–2009 on several transmission projects, as well as additional expenditures associated with the replacement of the steam generator and pressurizer at San Onofre. All amounts exceeding the October 2004 forecast are included in either the 2006 GRC or separate regulatory filings for major generation and transmission projects. Pursuant to the approved capital budget and forecast, SCE expects its capital expenditures to be \$1.8 billion, \$1.9 billion and \$2.1 billion in 2005, 2006 and 2007, respectively.

SCE has debt covenants that require certain interest coverage, interest and preferred dividend coverage, and debt to total capitalization ratios to be met. At September 30, 2005, SCE was in compliance with these debt covenants.

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

### **SCE: MARKET RISK EXPOSURES**

SCE's primary market risks include fluctuations in interest rates, commodity prices and volume, and counterparty credit. Fluctuations in interest rates can affect earnings and cash flows. However, fluctuations in commodity prices and volumes, and counterparty credit losses temporarily affect cash flows, but generally should not affect earnings due to recovery through regulatory mechanisms. SCE uses derivative financial instruments to manage its market risks, but does not use these instruments for speculative purposes. See "SCE: Market Risk Exposures" in the year-ended 2004 MD&A for a complete discussion of SCE's market risk exposures.

### **SCE: REGULATORY MATTERS**

This section of the MD&A describes SCE's regulatory matters in three main subsections:

- generation and power procurement;
- transmission and distribution; and
- other regulatory matters.

## Generation and Power Procurement

### *Energy Resource Recovery Account Proceedings*

In an October 2002 decision, the CPUC established the ERRA as the rate-making mechanism to track and recover SCE's: (1) fuel costs related to its generating stations; (2) purchased-power costs related to cogeneration and renewable contracts; (3) purchased-power costs related to existing interutility and bilateral contracts that were entered into before January 17, 2001; and (4) new procurement-related costs incurred on or after January 1, 2003 (the date on which the CPUC transferred back to SCE the responsibility for procuring energy resources for its customers). SCE recovers these costs on a cost-recovery basis, with no markup for return or profit. SCE files annual forecasts of the above-described costs that it expects to incur during the following year. As these costs are subsequently incurred, they will be tracked and recovered through the ERRA, but are subject to a reasonableness review in a separate annual ERRA application. If the ERRA overcollection or undercollection exceeds 5% of SCE's prior year's generation revenue, the CPUC has established a "trigger" mechanism, whereby SCE can request an emergency rate adjustment in addition to the annual forecast and reasonableness ERRA applications.

### *ERRA Reasonableness Review for the Period January 1, 2004 through December 31, 2004*

On April 1, 2005, SCE submitted an ERRA review application requesting that the CPUC find its procurement-related costs for calendar year 2004 to be reasonable, and that its contract administration and economic dispatch operations during 2004 complied with its CPUC-adopted procurement plan. In addition, SCE requested recovery of approximately \$13 million associated with Nuclear Unit Incentive Procedure rewards for efficient operation of the Palo Verde Nuclear Generating Station (Palo Verde) and approximately \$7 million in administrative and general costs incurred to carry out the CPUC's directive to begin procuring energy supplies on January 1, 2003 following the California energy crisis. In August 2005, the ORA recommended a \$16 million disallowance associated with SCE's 2004 sales of energy in the hour-ahead market, alleging that the price at which SCE sold its hour-ahead energy was unreasonable. SCE submitted its rebuttal testimony on September 15, 2005 contesting the ORA's recommendation. In addition, in its opening briefs, the ORA recommended that SCE be penalized \$37 million for allegedly having failed to prove that its least-cost dispatch operations complied with the methodology presented by the ORA. SCE believes the disallowance and recommended penalty are without merit. A decision is expected by the end of 2005.

### *2005 ERRA Forecast*

On March 17, 2005, the CPUC issued a final decision adopting SCE's requested ERRA revenue requirement of \$3.3 billion for the 2005 calendar year, an increase of \$1 billion over the 2004 revenue requirement. The increase was primarily attributable to increasing procurement costs, in part because SCE must procure additional energy and capacity in 2005 to replace energy and capacity that had been provided by a major California Department of Water Resources (CDWR) contract that terminated in December 2004. In addition, the increase was attributable to additional capacity and associated energy costs resulting from increasing SCE's reserve margin to fulfill the CPUC's requirement of a 15% to 17% planning reserve and a substantially higher forecasted ERRA undercollected balance as of December 31, 2004 than the balance included in 2004 rate levels.

### *2006 ERRA Forecast*

SCE submitted an ERRA forecast application on August 1, 2005, in which it forecasted a procurement-related revenue requirement for the 2006 calendar year of \$3.8 billion, an increase of \$509 million over SCE's adopted 2005 ERRA proceeding revenue requirement. The increase was mainly attributable to load growth and resource adequacy requirements (see the discussion under "—Generation Procurement Proceedings—Resource Adequacy Requirements" included in the year-ended 2004 MD&A), the

unavailability of SCE's Mohave coal-fired generating station (Mohave) after December 31, 2005, and its replacement with higher-cost natural gas generation (see "—Mohave Generating Station and Related Proceedings").

In addition, the 2006 ERRA forecast application requested that the CPUC consolidate all CPUC-authorized revenue requirements, including the revenue requirements from the 2006 ERRA forecast application, the 2006 GRC (see "—Transmission and Distribution—2006 General Rate Case Proceeding") and CDWR-related proceedings (see "—CDWR-Related Matters —CDWR Power Purchases and Revenue Requirement Proceeding"), for recovery through rates beginning January 1, 2006. SCE's current system average rate for bundled service customers is 12.6¢-per-kilowatt-hour (kWh). SCE expects the 2006 system average rate for bundled service customers to range between 14.3¢-per-kWh and 15.0¢-per-kWh.

### ***CDWR-Related Matters***

#### *CDWR Power Purchases and Revenue Requirement Proceedings*

As discussed in the "CDWR Power Purchases and Revenue Requirement Proceedings" disclosure in the year-ended 2004 MD&A, in December 2004, the CPUC issued its decision on how the CDWR's power charge revenue requirement for 2004 through 2013 would be allocated among the investor-owned utilities. On June 30, 2005, the CPUC granted, in part, San Diego Gas & Electric's (SDG&E) petition for modification of the December 2004 decision. The June 30, 2005 decision adopted a methodology that retains the cost-follows-contract allocation of the avoidable costs, and allocates the unavoidable costs associated with the contracts: 42.2% to Pacific Gas and Electric's (PG&E) customers, 47.5% to SCE's customers and 10.3% to SDG&E's customers. This newly adopted allocation methodology decreases the total costs allocated to SDG&E's customers and increases the total costs allocated to SCE's and PG&E's customers, relative to the December 2004 decision.

The burden of the additional costs, relative to the December 2004 decision, is borne almost entirely by SCE's customers for the period 2004–2009, and then shifts almost entirely to PG&E's customers in 2010–2011, when contract deliveries of CDWR energy to PG&E's customers falls by approximately 75%. SCE, joined by The Utility Reform Network (TURN) and the California Large Electricity Consumers Association (CLECA), filed a petition for modification of the June 30, 2005 decision, seeking to levelize the allocation of additional costs under the decision to SCE's and PG&E's customers and requesting clarification on other implementation issues. On November 2, 2005, the CPUC issued a proposed decision denying the petition for modification. The final decision is expected in December 2005.

The CDWR has submitted its 2006 revenue requirement determination to the CPUC for implementation. The CPUC must issue its final decision implementing the 2006 CDWR revenue requirement in December 2005. The November 2, 2005 proposed decision mentioned above also implement the CDWR's 2006 revenue requirement. A final decision is expected in December 2005.

Amounts billed to SCE's customers for electric power purchased and sold by the CDWR are remitted directly to the CDWR and are not recognized as revenue by SCE and therefore have no impact on SCE's earnings. In SCE's 2006 ERRA forecast proceeding, SCE is proposing to consolidate the impact of the June 30, 2005 decision, as well as other CDWR revenue requirement changes, with other changes in rates beginning on January 1, 2006 (see "—Energy Resource Recovery Account Proceedings—2006 ERRA Forecast").

## *Generation Procurement Proceedings*

SCE resumed power procurement responsibilities for its net-short position (expected load requirements exceed generation supply) on January 1, 2003, pursuant to CPUC orders and California statutes passed in 2002. The current regulatory and statutory framework requires SCE to assume limited responsibilities for CDWR contracts allocated by the CPUC, and provide full power procurement responsibilities on the basis of annual short-term procurement plans, long-term resource plans and increased procurement of renewable resources. Currently, the CPUC and the California Energy Commission are working together to set rules for various aspects of generation procurement which are described below.

### *Procurement Plan*

In December 2003, the CPUC adopted a short-term procurement plan for SCE which established a target level for spot market purchases equal to 5% of monthly need, and allowed SCE to enter into contracts of up to five years. Currently, SCE is operating under this approved short-term procurement plan. To the extent SCE procures power in accordance with the plan, SCE receives full-cost recovery of its procurement transactions pursuant to Assembly Bill 57. Accordingly, the plan is referred to as the Assembly Bill 57 component of the procurement plan.

Each quarter, SCE is required to file a report with the CPUC demonstrating that SCE's procurement-related transactions associated with serving the demands of its bundled electricity customers were in conformance with SCE's adopted short-term procurement plan. SCE has submitted quarterly compliance filings covering the period from January 1, 2003 through September 30, 2005. The CPUC issued one resolution approving SCE's first compliance report for the period January 1, 2003 to March 31, 2003 and issued a resolution approving the other transactions for calendar year 2003 in a June 16, 2005 resolution.

### *Resource Adequacy Requirements*

Under the framework adopted in the CPUC's January 22, 2004 decision, all load-serving entities in California have an obligation to procure sufficient resources to meet their customers' needs. On October 27, 2005, the CPUC issued a decision clarifying the January 2004 decision and a subsequent October 2004 decision on resource adequacy requirement. The October 2005 decision requires load-serving entities to ensure that adequate resources have been contracted to meet that entity's peak forecasted energy resource demand and an additional planning reserve margin of 15–17% in every month of the year, beginning in June 2006. The October 2005 decision requires that SCE demonstrate that it has contracted 90% of its June–September 2006 resource adequacy requirement by January 2006. By the end of May 2006, SCE will be required to fill out the remaining 10% of its resource adequacy requirement one month in advance of expected need. A month-ahead showing demonstrating that SCE has procured 100% of its resource adequacy requirement will be required every month thereafter. The October 2005 decision also adopted limits on the amount of a portfolio-sourced, as opposed to unit-specific, firm energy contract that can be used to meet a load serving entity's resource adequacy requirement. Under the October 2005 decision, a load-serving entity can have no more than 75% of its portfolio of resource adequacy resources met by such contracts in 2006, no more than 50% met by such contracts in 2007, and no more than 25% met by such contracts in 2008. No such contracts can be used to meet a load-serving entities' resource adequacy requirement after December 31, 2008. The October 2005 decision also clarified that the CDWR contracts, some of which are firm energy contracts, are not subject to the limitations. Additionally, the October 2005 decision adopted minimum elements for contracts upon which load-serving entities' may rely to meet their resource adequacy obligations. Further, the October 2005 decision deferred implementation of a local resource adequacy requirement until 2007. Lastly, the October 2005 decision adopted penalties of 150% of the cost of new monthly capacity for load serving entities that fail to acquire sufficient resources in 2006, and a 300% penalty in 2007 and beyond. SCE expects to meet its resource adequacy requirements by the deadlines set forth in the decision.

In July 2005, SCE issued a Request for Offers (RFO) whereby SCE solicited offers from sellers in the ISO control area for products that provide capacity, energy and resource adequacy benefits. In early October 2005, SCE executed a number of contracts for these products for terms up to 56 months.

#### *Procurement of Renewable Resources*

SCE's 2005 renewable procurement plan for 2005 through 2014 was filed on March 7, 2005. On July 21, 2005, the CPUC issued a decision approving SCE's renewable procurement plan for 2005 and deferred a ruling on SCE's renewable procurement plan for 2006 through 2014. This decision also approved the methodology advocated by SCE for determining the amount by which reported renewable procurement should be adjusted to reflect line losses. On October 6, 2005, the CPUC issued a decision conditionally approving SCE's renewable procurement plan for 2006 through 2014.

The CPUC's July 21, 2005 decision referenced above states that SCE cannot count procurement from certain geothermal facilities towards its 1% annual renewable procurement requirement, unless such procurement is from production certified as "incremental" by the California Energy Commission. A 2003 CPUC decision had held that SCE could count procurement from these geothermal facilities toward its 1% annual renewable procurement requirement. SCE is currently pursuing reconsideration of the July 21, 2005 decision.

The geothermal facilities have applied to the California Energy Commission for certification of a portion of the facilities' production as "incremental." A decision from the California Energy Commission is expected in November 2005. It is not clear whether any of the facilities' production will be certified as "incremental" or how much, if any, of the "incremental" production from the facilities will be allocated to SCE's procurement under its contract with the facilities if the California Energy Commission certification is granted.

Depending upon the amount, if any, of California Energy Commission certified "incremental" production allocated to SCE's procurement under its contract and the manner in which the CPUC implements its flexible rules for compliance with renewable procurement obligations, the CPUC could deem SCE to be out of compliance with its statutory renewable procurement obligations for the years 2003, 2004 and 2005, and therefore SCE could be subject to penalties for those years. In addition, the California Energy Commission's and the CPUC's treatment of the production from the geothermal facilities could result in SCE being deemed to be out of compliance with its obligations for 2006. The maximum penalty for noncompliance is \$25 million per year. To comply with renewable procurement mandates and avoid penalties for years beyond 2006, SCE will either need to sign new contracts and/or extend existing renewable qualifying facility (QF) contracts.

SCE received bids for renewable resource contracts in response to a solicitation it made in August 2003 and conducted negotiations with bidders regarding potential procurement contracts. On June 30, 2005, the CPUC issued a resolution approving six renewable contracts resulting from the solicitation. On August 11, 2005 and August 31, 2005, SCE submitted advice letters seeking CPUC approval of two additional renewable contracts resulting from the solicitation.

The CPUC's July 21, 2005 decision referenced above also approved SCE's proposed new request for proposals for additional renewable contracts. SCE issued its 2005 request for proposals for renewable contracts on September 2, 2005. Proposals for renewable contracts have been received and are being evaluated.

#### *Request for Offers for New Generation Resources*

According to California state agencies, beginning in 2006, there is a need for new generation capacity in southern California. SCE has issued an RFO for new generation resources. SCE solicited offers for

power-purchase agreements lasting up to 10 years from new generation facilities with delivery under the agreement beginning between June 1, 2006 and August 1, 2008. SCE filed an application with the CPUC seeking approval of the RFO and the power-purchase agreements executed under the RFO. SCE sought recovery of the costs of the contracts, through the FERC-jurisdictional rates, from all affected customers. In addition, SCE sought CPUC assurance of full cost recovery in CPUC-approved rates, if the FERC denies any recovery. On September 9, 2005, the CPUC issued a scoping memorandum rejecting SCE's proposal. Since the scoping memorandum did not provide a mechanism for SCE to secure new generation on behalf of these customers, SCE terminated its RFO and moved to stay the proceeding and withdraw the CPUC application. A stay was granted on September 22, 2005. The motion to withdraw is still pending.

### ***Mohave Generating Station and Related Proceedings***

As discussed in the "Mohave Generating Station and Related Proceedings" disclosure in the year-ended 2004 MD&A, the CPUC issued a final decision in December 2004 on SCE's application regarding the post-2005 operation of Mohave, which is partly owned by SCE.

In parallel with and since the conclusion of the CPUC proceeding, negotiations, water studies, and other efforts have continued among the relevant parties in an attempt to resolve Mohave's post-2005 coal and water supply issues. Although progress has been made with respect to certain issues, no complete resolution has been reached to date. Because resolution has not been reached and because of the lead times required for installation of certain pollution-control equipment and other upgrades necessary for post-2005 operation, it appears probable that Mohave will temporarily shut down at the end of 2005, and a permanent shutdown remains possible. The outcome of the efforts to resolve the post-2005 coal and water supply issues is not expected to impact Mohave's operation through 2005, but the presence or absence of Mohave as an available resource beyond 2005 will impact SCE's long-term resource plan. SCE's 2006 ERRA forecast application assumes Mohave is an unavailable resource for power for 2006 (see "—Energy Resource Recovery Account Proceedings—2006 ERRA Forecast" for further discussion). Because SCE expects to recover Mohave shut-down costs in future rates, the outcome of this matter is not expected to have a material impact on earnings.

### ***San Onofre Nuclear Generating Station***

As discussed in the "San Onofre Nuclear Generating Station" disclosure in the year-ended 2004 MD&A, there are several issues related to the operation and maintenance of San Onofre Units 2 and 3. The following are new developments with respect to San Onofre.

#### ***San Onofre Steam Generators***

On October 31, 2005, an assigned administrative law judge issued a proposed decision on the reasonableness of the proposed replacement of the San Onofre Units 2 and 3 steam generators and the establishment of appropriate ratemaking for recovery in rates of the reasonable cost of the replacement project. The proposed decision found that: (1) steam generator replacement is "marginally cost-effective"; (2) \$680 million (\$569 million for replacement steam generator installation and \$111 million for removal and disposal of the original steam generators) is a reasonable estimate; (3) SCE will not be allowed to recover costs above \$680 million for steam generator replacement; (4) SCE will be required to file an application for reasonableness review of steam generator replacement upon completion of that work; (5) SCE can recover 20% of the estimated costs of removal and disposal of the steam generators through depreciation during 2006–2011; (6) SCE will be prohibited from recovering San Onofre Units 2 and 3 O&M costs above levels forecast in its test year 2006 GRC forecast plus 10% through 2022; (7) SCE will be prohibited from recovering San Onofre Units 2 and 3 capital expenditures above levels forecast in its test year 2006 GRC plus 25% through 2022; and (8) SCE acted reasonably in relation to the issue of potential claims against the manufacturer of the steam generators or its successors. Opening

comments on the proposed decision are due November 21, 2005, and reply comments are due November 28, 2005. The CPUC may adopt, reject, or modify a proposed decision. SCE anticipates that the CPUC will issue a final decision by early next year. If the CPUC authorizes SCE to go forward with steam generator replacement under terms that reasonably compensate SCE for the risk of operating San Onofre Units 2 and 3, SCE will recover costs that are reasonably incurred as part of the steam generator replacement capital costs. By the time of the expected final decision, SCE anticipates that it will have incurred approximately \$80 million in steam generator fabrication and associated project costs. SCE will seek recovery of these costs in the event that the CPUC does not authorize SCE to go forward with steam generator replacement under terms that reasonably compensate it for the risk that it undertakes by operating San Onofre Units 2 and 3. However, there is no assurance that the CPUC would approve such a request.

### *San Onofre Reactor Vessel Heads*

During the ongoing San Onofre Unit 3 refueling outage in the fourth quarter of 2004, SCE conducted a planned inspection of the Unit 3 reactor vessel head and found indications of degradation. Although the indications of degradation were far below the level at which leakage would occur, SCE repaired these indications of degradation using readily available tooling and a Nuclear Regulatory Commission-approved repair technique. While this was San Onofre's first experience of this kind of degradation to the reactor vessel head, the detection and repair of similar degradation is now common in the industry. SCE plans to replace the Unit 2 and 3 reactor vessel heads during the planned refueling outages in 2011–2012.

### *Palo Verde Steam Generators*

#### *Palo Verde Steam Generator Replacement*

The steam generators at Palo Verde, in which SCE owns a 15.8% interest, have material properties that are similar to the San Onofre units. During 2003, the Palo Verde Unit 2 steam generators were replaced. In addition, the Palo Verde owners have approved the manufacture and installation of steam generators in Units 1 and 3. On October 8, 2005, Palo Verde Unit 1 commenced an outage during which the steam generators will be replaced. Unit 1 will return to service after the successful completion of its planned refueling and maintenance outage including steam generator replacement. The outage is scheduled to last 75 days. The Palo Verde owners expect that replacement steam generators will be installed in Unit 3 in the 2007 to 2008 time frame. SCE's share of the costs of manufacturing and installing all the replacement steam generators at Palo Verde is estimated to be about \$115 million; SCE expects to recover these costs through the rate-making process.

Inspections of Palo Verde Units 1, 2 and 3 reactor vessel heads were performed during scheduled refueling and maintenance outages in 2003 and 2004 and no indications of leakage or degradation were found.

## **Transmission and Distribution**

### *2006 General Rate Case Proceeding*

On December 21, 2004, SCE filed its application for a 2006 GRC, requesting a 2006 base rate revenue requirement of \$4.06 billion, an increase of \$370 million over SCE's base rate revenue. The increase is primarily for capital-related expenditures to accommodate infrastructure replacement, and customer and load growth. The requested increase is also necessary to fund substantially higher O&M expenses, particularly in SCE's transmission and distribution business unit. SCE also requested that the CPUC authorize the continuation of SCE's existing post-test year rate-making mechanism, which would result in

further base rate revenue increases of \$159 million above the 2006 request in 2007, and \$122 million above the 2007 request in 2008.

As part of the GRC process, on April 15, 2005, the ORA submitted testimony proposing adjustments to reduce SCE's requested 2006 base rate revenue requirement to \$3.55 billion. In addition, the ORA recommended that an additional year, 2009, be added to SCE's GRC cycle and that the CPUC use a Consumer Price Indexed (CPI) method, applied to the test year revenue requirement, to determine base rate revenue adjustments in the attrition years (2007 and 2008). SCE had used a budget-based approach to projected capital additions in the attrition years in its filing as previously authorized in the 2003 GRC decision.

During the course of the GRC proceeding, SCE agreed to certain revisions to its request, updated the revenue requirement for the 2005 cost of capital, and incorporated a second refueling and maintenance outage in the O&M expense forecast for San Onofre in 2006. In addition, on September 26, 2005, SCE submitted updated testimony and revised its requested revenue requirement to reflect the current forecast of 2006–2008 escalation rates, a pending postage rate increase, revised tax depreciation rates, and the company's current scenario for costs to operate the Mohave Generating Station. SCE's revised requested 2006 base rate revenue requirement is \$3.96 billion, an increase of \$325 million over SCE's 2005 base rate revenue, as set forth in an exhibit on October 17, 2005. SCE also proposed revised base rate revenue increases of \$108 million for 2007 and \$113 million for 2008.

During the course of the GRC proceeding, the ORA revised its proposed 2006 base rate revenue requirement for SCE to also incorporate a second refueling outage in the O&M expense forecast for San Onofre in 2006 among other changes. The ORA's current proposed 2006 base rate revenue requirement is \$3.59 billion, with further base rate increases of \$24 million for 2007 and \$75 million for 2008. In addition, several intervenors have proposed further adjustments, totaling \$230 million to reduce SCE's requested 2006 rate base revenue requirement.

On August 2, 2005 SCE filed a motion requesting the establishment of a GRC Memo Account which would make the GRC decision retroactive to January 9, 2006, or the first CPUC meeting in January 2006, whichever is earlier.

A final CPUC decision is expected in January 2006. SCE cannot predict with certainty the final outcome of SCE's GRC application.

### ***2006 Cost of Capital***

On May 9, 2005, SCE filed an application requesting that the CPUC authorize a return on SCE's common equity and an overall rate of return for SCE's CPUC-jurisdictional assets for 2006. In its application, SCE requested that the CPUC maintain its 2005 authorized rate-making capital structure of 43% long-term debt, 9% preferred equity and 48% common equity for 2006. SCE's application also requested that the CPUC authorize SCE's 2006 cost of long-term debt of 6.53%, cost of preferred equity of 6.43% and a return on common equity of 11.80%. A proposed decision is scheduled for November 15, 2005, and a final CPUC decision is anticipated on or before December 15, 2005. CPUC adoption of SCE's application request would result in a projected \$10 million increase in its annual revenue requirements. Based on the September 2005 economic forecasts of average long-term utility bond and other interest rates for 2006, adoption of SCE's application request is expected to now result in a projected \$10 million decrease in SCE's annual revenue requirements with an anticipated 2006 cost of long-term debt of 6.17% and cost of preferred equity of 6.09%.

### ***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 charges. The order reversed an arbitrator's award that had affirmed the ISO's characterization in May 2000 of the charges as Intra-Zonal Congestion costs and allocation of those charges to Scheduling Coordinators (SCs) in the affected zone within the ISO transmission grid. The April 20, 2004 order directed the ISO to shift the costs from SCs in the affected zone to the responsible Participating Transmission Owner, SCE, and to do so within 60 days of the April 20, 2004 order. Under the April 20, 2004 order, which was stayed pending resolution of SCE's rehearing request, SCE would be charged a certain amount as the Participating Transmission Owner but also would be credited in its role as an SC and through the California Power Exchange, to the extent it acted as SCE's SC. On March 30, 2005, the FERC issued an Order Denying Rehearing. SCE obtained an extension of the stay pending resolution of the appeal SCE filed with the Court of Appeals for the D.C. Circuit. A briefing schedule has been set in the appeal with SCE's opening brief due on December 23, 2005. The potential net impact on SCE is estimated to be approximately \$20 million to \$25 million, including interest. SCE filed a request for clarification with the FERC asking the FERC to clarify that SCE can reflect and recover the disputed costs in SCE's reliability services rates. On June 8, 2005, the FERC denied the clarification, noting that during the appeal, the FERC's order is stayed, and therefore SCE is not required to pay at this time. SCE may seek recovery in its reliability service rates of the costs should SCE be required to pay these costs.

### ***Transmission Proceeding***

In August and November 2002, the FERC issued opinions affirming a September 1999 administrative law judge decision to disallow, among other things, recovery by SCE and the other California public utilities of costs reflected in network transmission rates associated with ancillary services and losses incurred by the utilities in administering existing wholesale transmission contracts after implementation of the restructured California electric industry. SCE has incurred approximately \$80 million of these unrecovered costs since 1998. In addition, SCE has accrued interest on these unrecovered costs. The three California utilities appealed the decisions to the Court of Appeals for the Federal Circuit. On July 12, 2005, the Court of Appeals for the Federal Circuit vacated the FERC's August and November 2002 orders, and remanded the case to the FERC for further proceedings. SCE believes that the Court of Appeals for the Federal Circuit's decision increases the likelihood that it will recover these costs.

### ***Wholesale Electricity and Natural Gas Markets***

As discussed in the "Wholesale Electricity and Natural Gas Markets" disclosure in the year-ended 2004 MD&A, SCE is participating in several related proceedings seeking recovery of refunds from sellers of electricity and natural gas who allegedly manipulated the electric and natural gas markets.

El Paso Natural Gas Company (El Paso) entered into a settlement agreement with a number of parties (including SCE, PG&E, the State of California and various consumer class action representatives) settling various claims stated in proceedings at the FERC and in San Diego County Superior Court that El Paso had manipulated interstate capacity and engaged in other anticompetitive behavior in the natural gas markets in order to unlawfully raise gas prices at the California border in 2000–2001. The United States District Court has issued an order approving the stipulated judgment and the settlement agreement has become effective. Pursuant to a CPUC decision, SCE was required to refund to customers amounts received under the terms of the El Paso settlement (net of legal and consulting costs) through its ERRRA mechanism. In June 2004, SCE received its first settlement payment of \$76 million. Approximately \$66 million of this amount was credited to purchased-power expense, and was refunded to SCE's ratepayers through the ERRRA over the following twelve months, and the remaining \$10 million was used to offset SCE's incurred legal costs. El Paso has elected to prepay the additional settlement payments due over a 20-year period and, as a result, SCE received \$66 million in May 2005. Amounts El Paso refunds

to the CDWR will result in reductions in the CDWR's revenue requirement allocated to SCE in proportion to SCE's share of the CDWR's power charge revenue requirement.

On January 14, 2005, SCE, PG&E, SDG&E and several governmental entities agreed to settlement terms with Mirant Corporation and a number of its affiliates (collectively Mirant), all of whom are debtors in Chapter 11 bankruptcy proceedings pending in Texas. Among other things, the settlement terms provide for cash and equivalent refunds totaling \$320 million, of which SCE's allocated share is approximately \$68 million. The settlement also provides for an allowed, unsecured claim totaling \$175 million in the bankruptcy of one of the Mirant parties, with SCE being allocated approximately \$33 million of the unsecured claim. The actual value of the unsecured claim will be determined as part of the resolution of the Mirant parties' bankruptcies. The Mirant settlement was approved by the FERC on April 13, 2005 and by the bankruptcy court on April 15, 2005. In April and May 2005, SCE received its allocated \$68 million in cash settlement proceeds. SCE continues to hold its \$33 million share of the allowed, unsecured bankruptcy claim. The Mirant settlement will be refunded to ratepayers as described below.

On July 15, 2005, SCE, PG&E, SDG&E and several governmental entities agreed to settlement terms with Enron Corporation and a number of its affiliates (collectively Enron), most of which are debtors in Chapter 11 bankruptcy proceedings pending in New York. Among other things, the settlement terms provide for cash and equivalent payments from Enron totaling approximately \$47 million and an allowed, unsecured claim in the bankruptcy against one of the Enron entities in the amount of \$875 million. SCE's allocable share of both the cash and allowed claim portions of the settlement consideration has not yet been finally determined, and the value of an allocable share of the allowed claim will be determined as part of the resolution of the Enron parties' bankruptcies. The settlement was approved by the Enron bankruptcy court on October 20, 2005, but remains subject to approval by the FERC. Effective August 24, 2005, the CPUC approved the settlement by entering into an agreement incorporating its terms. The Enron settlement proceeds will be refunded to ratepayers as described below.

On August 12, 2005, SCE, PG&E, SDG&E, several governmental entities and certain other parties agreed to settlement terms with Reliant Energy, Inc. and a number of its affiliates (collectively Reliant). Among other things, the settlement terms provide for Reliant to provide cash and cash equivalents having a total value of at least \$460 million, which would be in addition to the \$65 million in refunds that Reliant was already required to provide pursuant to prior FERC orders. SCE expects that its allocable share of the entire settlement value of \$525 million (including the amounts previously ordered by the FERC) will be approximately \$130 million. The settlement remains subject to FERC approval, which is anticipated in the first quarter of 2006. Effective October 12, 2005, the CPUC approved the settlement by entering into an agreement incorporating its terms. The Reliant settlement proceeds will be refunded to ratepayers as described below.

On November 19, 2004, the CPUC issued a resolution authorizing SCE to establish an Energy Settlement Memorandum Account (ESMA) for the purpose of recording the foregoing settlement proceeds (excluding the El Paso settlement) from energy providers and allocating them in accordance with the terms of the October 2001 settlement agreement entered into by SCE and the CPUC which settled SCE's lawsuit against the CPUC. This lawsuit sought full recovery of SCE's electricity procurement costs incurred during the energy crisis. The resolution provides a mechanism whereby portions of the settlement proceeds recorded in the ESMA will be allocated to recovery of SCE's litigation costs and expenses in the FERC refund proceedings described above and a 10% shareholder incentive pursuant to the CPUC litigation settlement agreement. Remaining amounts for each settlement are to be refunded to ratepayers through the ERRRA mechanism. In the second quarter of 2005, SCE recorded a \$7 million increase to other nonoperating income as a shareholder incentive related to the Mirant refund received during the second quarter of 2005.

## ***Schedule Coordinator Tariff Dispute***

SCE serves as an SC for Los Angeles Department of Water & Power (DWP) over the ISO-controlled grid. In mid-2003, SCE filed a petition asking that the FERC accept a tariff that provides for a direct pass-through of the FERC-authorized charges incurred by SCE on the DWP's behalf. The DWP protested SCE's filing. The DWP asked the FERC to declare that SCE was obligated to serve as the DWP's SC without charge. In late 2003, the FERC accepted the tariff, subject to refund. The FERC held that the proposed tariff has not been shown to be just and reasonable.

In accordance with to the terms of the tariff, SCE issued several invoices for charges to the DWP. The DWP has objected to all of the charges but has paid, under protest, approximately \$18 million. The DWP has protested specific charges totaling approximately \$5 million based on its allegations that those specific charges are improper for various reasons.

The FERC has not issued a final order on this issue. SCE could be required to refund all or part of the amounts collected under the tariff. SCE continues to invoice the DWP. Monthly invoices have been averaging approximately \$1 million. SCE cannot predict with certainty the outcome of the FERC final order.

## **Other Regulatory Matters**

### ***Catastrophic Event Memorandum Account***

#### ***Fire-Related CEMA***

In October and November of 2003, wildfires damaged SCE's electrical infrastructure, primarily in the San Bernardino Mountains of southern California where an estimated 2,085 power poles, 2,059 services, 371 transformers, 557,033 of overhead conductors and 25,822 feet of underground cable were replaced or repaired. SCE notified the CPUC that it initiated a CEMA on October 21, 2003 to track the incremental costs to restore and repair damage to its facilities. SCE filed an application with the CPUC on December 2, 2004 to seek recovery of its fire-related costs over a one-year period commencing January 1, 2006. In an August 25, 2005 decision, the CPUC approved the settlement agreement between SCE and the ORA which (1) allows the authorized fire-related CEMA revenue requirement calculation to be based on approximately \$8 million of incremental operations and maintenance expenses and \$20 million of incremental capital plant additions and (2) allows SCE to continue to record in its fire-related CEMA the revenue requirement associated with these costs, plus accrued interest, until the effective date of the final decision in SCE's 2006 GRC. The revenue requirement recorded in SCE's fire-related CEMA through April 2005 is approximately \$12 million. SCE has forecast the recorded revenue requirement in this account to total approximately \$14 million in December 2005. SCE expects to recover the costs recorded in the fire-related CEMA account through a mechanism approved in SCE's 2006 GRC.

### ***Holding Company Proceeding and Order Instituting Rulemaking***

In April 2001, the CPUC issued an order instituting investigation that reopened the past CPUC decisions authorizing utilities to form holding companies and initiated an investigation into, among other things: (1) whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; (2) any additional suspected violations of laws or CPUC rules and decisions; and (3) whether additional rules, conditions, or other changes to the holding company decisions are necessary. For a discussion of item (1) above, see the "SCE: Regulatory Matters—Other Regulatory Matters—Holding Company Proceeding" disclosure in the year-ended 2004 MD&A.

On May 5, 2005, the CPUC issued a final decision that closed the proceeding. However, because the CPUC closed the proceeding without addressing some of the issues the proceeding raised (such as the

appropriateness of the large utilities' holding company structure and dividend policies), the CPUC may rule on or investigate these issues in the future.

On October 27, 2005, the CPUC issued an order instituting rulemaking (OIR) to allow the CPUC to re-examine the relationships of the major California energy utilities with their parent holding companies and non-regulated affiliates. The OIR was issued in part in response to the recent repeal of the Public Utility Holding Company Act of 1935.

By means of the OIR the CPUC will consider whether additional rules to supplement existing rules and requirements governing relationships between the public utilities and their holding companies and non-regulated affiliates should be adopted. Any additional rules will focus on whether (1) the public utilities retain enough capital or access to capital to meet their customers' infrastructure needs and (2) mitigation of potential conflicts between ratepayer interests and the interests of holding companies and affiliates that could undermine the public utilities' ability to meet their public service obligations at the lowest cost. The CPUC expects to issue proposed rules in January 2006, and a final decision is expected in March 2006.

### ***System Reliability Incentive Mechanism***

SCE's 2003 GRC decision provided for performance incentives or penalties for differences between SCE's actual results and CPUC-authorized standards for system reliability measures beginning in 2004. In a March 30, 2005 advice letter, SCE reported a \$2 million penalty and recorded an accrual in 2004 for its 2004 results under the modified reliability mechanism. On April 28, 2005, the CPUC agreed to suspend its review of SCE's advice letter for 2004 results until the CPUC's Consumer Protection and Safety Division has completed its investigation regarding performance incentive rewards discussed in the 2004 year-ended MD&A. Based on preliminary recorded data through September 2005 and a forecast of normal results through December 2005, SCE projects it will incur a penalty of \$26 million under the reliability performance mechanism for 2005. The maximum penalty that could be assessed under the reliability performance mechanism is approximately \$40 million. As a result, during the third quarter of 2005, SCE recorded an accrual of \$26 million that is reflected in the income statement caption "Other nonoperating deductions."

### ***Demand-Side Management and Energy Efficiency Performance Incentive Mechanisms***

Under a variety of incentive mechanisms adopted by the CPUC in the past, SCE was entitled to certain shareholder incentives for its performance achievements in delivering demand-side management and energy efficiency programs. On June 10, 2005, SCE and the ORA executed a settlement agreement for SCE's outstanding issues concerning SCE shareholder incentives and performance achievements resulting from the demand-side management, energy efficiency, and low-income energy efficiency programs from program years 1994–2004. In addition, the settlement addresses shareholder incentives and performance achievements for program years 1994–1998, anticipated but not yet claimed. The settlement agreement recommends, among other things, that SCE be entitled to immediately recover 92% of the total of SCE's current claims and future claims related to SCE's pre-1998 energy efficiency programs. SCE's total claim for program years 1994–2004 made in 2000 through 2008, including interest, franchise fees and uncollectibles, is approximately \$46 million. On October 27, 2005, the CPUC approved the settlement agreement which found it reasonable for SCE to recover approximately \$42 million of these claims which include all of SCE's outstanding claims, as well as future claims related to SCE's pre-1998 energy efficiency programs (of which approximately \$9 million has already been collected in rates). The remaining portion of claims in the amount of \$33 million will be recognized in the fourth quarter of 2005. As a result of the decision, during the third quarter of 2005, SCE recognized \$14 million of incentives previously awarded for which revenue recognition was deferred pending final resolution of these matters. The \$14 million is reflected in the income statement caption "Other nonoperating income." In addition, \$4 million related to interest on the claims was reflected in the caption "Interest and dividend income."



## MISSION ENERGY HOLDING COMPANY

### MEHC: LIQUIDITY

#### Introduction

MEHC's liquidity discussion is organized in the following sections:

- MEHC (parent)'s Liquidity
- EME's Liquidity
- Midwest Generation Financing
- Capital Expenditures
- MEHC and EME's Credit Ratings
- Margin, Collateral Deposits and Other Credit Support for Energy Contracts
- EME's Liquidity as a Holding Company
- Dividend Restrictions in Major Financings
- MEHC's Interest Coverage Ratio

#### MEHC (parent)'s Liquidity

At September 30, 2005, MEHC had cash and cash equivalents of \$30 million (excluding amounts held by EME and its subsidiaries). MEHC's ability to honor its obligations under the senior secured notes and to pay overhead is substantially dependent upon the receipt of dividends from EME and receipt of tax-allocation payments from MEHC's parent, Edison Mission Group, and ultimately Edison International. See "—EME's Liquidity as a Holding Company—Intercompany Tax-Allocation Agreement." Dividends from EME are limited based on its earnings and cash flow, terms of restrictions contained in EME's corporate credit facility, business and tax considerations and restrictions imposed by applicable law. For a description of material dividend restrictions, see "MEHC: Liquidity—Dividend Restrictions in Major Financings" in the year-ended 2004 MD&A.

MEHC is required to offer to repurchase the senior secured notes at par plus interest if proceeds in excess of \$20 million from the sale of assets are not otherwise used to pay debt or reinvested as permitted under the terms of such notes within twelve months from the date of sale (on or before December 15, 2005, with respect to the sale of the stock and related assets of MECIBV). MEHC does not expect to use or reinvest all of the excess proceeds from the sale within the twelve-month period and, accordingly, MEHC expects to make an offer to repurchase the senior secured notes in accordance with the terms of the indenture. Because the senior secured notes currently trade at prices greater than par, MEHC does not currently expect holders of the senior secured notes to accept its offer.

#### *Dividends to MEHC (parent)*

In January 2005, EME made total dividend payments of \$360 million to MEHC (parent). A portion of these payments was used to repay the remaining \$285 million of MEHC's term loan plus interest on January 3, 2005.

#### EME's Liquidity

At September 30, 2005, EME and its subsidiaries had cash and cash equivalents of \$1.6 billion and EME had available the full amount of borrowing capacity under a \$98 million corporate credit facility. EME's consolidated debt at September 30, 2005 was \$3.4 billion. In addition, EME's subsidiaries had \$5.0 billion of long-term lease obligations that are due over periods ranging up to 30 years.

## **Midwest Generation Financing**

On April 18, 2005, Midwest Generation completed a refinancing of indebtedness. The refinancing was effected through the amendment and restatement of Midwest Generation's existing credit facility, originally entered into April 27, 2004. The existing credit facility had provided for a \$700 million first priority secured institutional term loan due in 2011 and a \$200 million first priority secured revolving credit, working capital facility due in 2009.

The refinancing consisted of, among other things, a repricing of Midwest Generation's existing term loan and a new \$300 million revolving credit, working capital facility due in 2011. The previously existing \$200 million working capital facility remains in place. Midwest Generation drew in full upon the new \$300 million working capital facility at closing and used the proceeds to pay down an equivalent portion of the existing term loan. After giving effect to the paydown, the term loan carries a lower interest rate of LIBOR + 2%. The maturity date of the repriced term loan remains 2011. The new working capital facility, together with the existing working capital facility, shares first lien priority with the repriced term loan. The new working capital facility carries an interest rate of LIBOR + 2.25%. The maturity date of the new working capital facility is 2011; however, the lenders can request to be fully repaid in 2010.

On the day after the closing of the refinancing transaction, EME contributed \$300 million in equity to Midwest Generation, and Midwest Generation used the proceeds of this equity contribution to repay the loans outstanding under the new working capital facility. Thus, after completion of the actions outlined herein, Midwest Generation had \$343 million outstanding under its term loan and \$500 million of working capital facilities available for working capital requirements, including credit support for hedging activities. As of September 30, 2005, approximately \$170 million was utilized under these working capital facilities.

Under the terms of Midwest Generation's credit agreement, Midwest Generation is permitted to distribute 75% of excess cash flow (as defined in the credit agreement). In addition, if equity is contributed to Midwest Generation, Midwest Generation is permitted to distribute 100% of excess cash flow until the aggregate portion of distributions that Midwest Generation attributes to the equity contribution equals the amount thereof. Accordingly, Midwest Generation is permitted to distribute 100% of excess cash flow until the aggregate portion of such distributions attributed to the equity contribution made by EME in Midwest Generation on April 19, 2005 equals \$300 million. However, Midwest Generation is required to make concurrently with each distribution an offer to repay debt in an amount equal to the excess, if any, of one-third of such distribution over the portion thereof attributed to the equity contribution. Thus, Midwest Generation will not be required to offer to repay debt concurrently with a distribution so long as the portion of each distribution attributed to the April 19, 2005 equity contribution is at least one-third of such distribution.

## **Capital Expenditures**

The estimated capital and construction expenditures of EME's subsidiaries are \$14 million for the final quarter of 2005 and \$63 million and \$49 million for 2006 and 2007, respectively. Non-environmental expenditures relate to upgrades to dust collection/mitigation systems and the coal handling system, ash removal improvements and various other projects. EME plans to finance these expenditures with existing subsidiary credit agreements, cash on hand or cash generated from operations. Included in the estimated expenditures are environmental expenditures of \$4 million for the final quarter of 2005, \$8 million for 2006 and \$6 million for 2007. The environmental expenditures relate to environmental projects such as selective catalytic reduction system improvements at the Homer City facilities.

## MEHC and EME's Credit Ratings

### Overview

Credit ratings for MEHC and its subsidiaries, EME, Midwest Generation, LLC and Edison Mission Marketing & Trading, are as follows:

	Moody's Rating	S&P Rating
MEHC	B2	CCC+
EME	B1	B+
Midwest Generation, LLC:		
First priority senior secured rating	Ba3	BB-
Second priority senior secured rating	B1	B
Edison Mission Marketing & Trading	Not Rated	B+

MEHC 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. MEHC 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.

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

The credit ratings of EME are below investment grade and, accordingly, EME has historically provided collateral in the form of cash and letters of credit for the benefit of counterparties for its price risk management and trading activities related to accounts payable and unrealized losses.

### *Credit Rating of Edison Mission Marketing & Trading*

The Homer City sale-leaseback documents restrict EME Homer City Generation L.P.'s (EME Homer City's) ability to enter into trading activities, as defined in the documents, with Edison Mission Marketing & Trading to sell forward the output of the Homer City facilities if Edison Mission Marketing & Trading does not have an investment grade credit rating from Standard & Poor's 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 Edison Mission Marketing & Trading, which has a below investment grade credit rating, and EME Homer City is not rated. Therefore, in order for EME to continue to sell forward the output of the Homer City facilities, either: (1) EME must obtain consent from the sale-leaseback owner participant to permit EME Homer City to sell directly into the market or through Edison Mission Marketing & Trading; or (2) Edison Mission Marketing & Trading must provide assurances of performance consistent with the requirements of the sale-leaseback documents. EME has obtained a consent from the sale-leaseback owner participant that will allow EME Homer City to enter into such sales, under specified conditions, through December 31, 2006. EME Homer City continues to be in compliance with the terms of the consent; however, the consent is revocable by the sale-leaseback owner participant at any time. The sale-leaseback owner participant has not indicated that it intends to revoke the consent; however, there can be no assurance that it will not do so in the future. Revocation of the consent would not affect trades between Edison Mission Marketing & Trading and EME Homer City that had been entered into while the consent was still in effect. EME is permitted to sell the output of the Homer City facilities into the spot market at any time. See "MEHC: Market Risk Exposures—Commodity Price Risk—Energy Price Risk Affecting Sales from the Homer City Facilities."

## **Margin, Collateral Deposits and Other Credit Support for Energy Contracts**

In connection with entering into energy contracts (including forward contracts, transmission contracts and futures contracts), EME's subsidiary, Edison Mission Marketing & Trading, has entered into agreements to support the risk of nonperformance. At September 30, 2005, Edison Mission Marketing & Trading had deposited \$516 million in cash with brokers in margin accounts in support of futures contracts and had deposited \$210 million with counterparties in support of forward energy and transmission contracts. These margin and collateral deposits are used in support of EME's price risk management and energy trading activities. The margin and collateral deposits generally earn interest at a rate that approximates the Federal Funds Rate. In addition, EME has issued letters of credit of \$6 million in support of commodity contracts at September 30, 2005.

Margin and collateral deposits increased substantially during the third quarter of 2005 due to higher wholesale energy prices and increased megawatt hours hedged. Future cash collateral requirements may be higher than the margin and collateral requirements at September 30, 2005, if wholesale energy prices increase further. Using the amount of energy contracts outstanding at September 30, 2005, EME estimates that margin and collateral requirements could increase by approximately \$300 million using a 95% confidence interval and an internal model estimate using historical volatility.

Midwest Generation has \$500 million in credit facilities to support margin requirements specifically related to contracts entered into by Edison Mission Marketing & Trading related to the Illinois plants. At September 30, 2005, Midwest Generation has borrowed \$165 million under these credit facilities to finance margin advances to Edison Mission Marketing & Trading of \$316 million. The balance of the margining advances by Midwest Generation was provided through cash on hand. In addition, EME has cash on hand and a \$98 million working capital facility to provide credit support to subsidiaries. See “—EME's Liquidity” for further discussion.

## **EME's Liquidity as a Holding Company**

### *Overview*

At September 30, 2005, EME had corporate cash and cash equivalents of \$1.3 billion to meet liquidity needs. See “—EME's Liquidity.” EME had no borrowings outstanding or letters of credit outstanding on the \$98 million secured line of credit at September 30, 2005. Cash distributions from EME's subsidiaries and partnership investments, and unused capacity under its corporate credit facility represent EME's major sources of liquidity to meet its cash requirements. The timing and amount of distributions from EME's subsidiaries may be affected by many factors beyond its control. See “—Dividend Restrictions in Major Financings.”

EME's secured corporate credit facility provides credit available in the form of cash advances or letters of credit. In addition to the interest payments, EME pays a commitment fee of 0.50% on the unutilized portion of the facility. EME has agreed to maintain a minimum interest coverage ratio and a minimum recourse debt to recourse capital ratio (as such ratios are defined in the credit agreement). At September 30, 2005, EME met both these ratio tests.

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

At September 30, 2005, EME also had available \$88 million under Midwest Generation EME, LLC's \$100 million letter of credit facility with Citibank, N.A., as Issuing Bank, that expires in December 2006.

Under the terms of this letter of credit facility, Midwest Generation EME is required to deposit cash in a bank account in order to cash collateralize any letters of credit that may be outstanding under the facility. The bank account is pledged to the Issuing Bank. Midwest Generation EME owns 100% of Edison Mission Midwest Holdings, which in turn owns 100% of Midwest Generation, LLC.

### ***Historical Distributions Received By EME***

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

In millions	Nine Months Ended September 30,	2005	2004
<b>Distributions from Consolidated Operating Projects:</b>			
Edison Mission Midwest Holdings (Illinois plants) ) <sup>(1)</sup>		<b>\$ 171</b>	\$ —
EME Homer City Generation L.P. (Homer City facilities) <sup>(2)</sup>		<b>62</b>	61
Holding companies of other consolidated generating projects		<b>1</b>	—
<b>Distributions from Unconsolidated Operating Projects:</b>			
Edison Mission Energy Funding Corp. (Big 4 projects) <sup>(3)</sup>		<b>93</b>	80
Sunrise Power Company		<b>5</b>	5
Holding company for Doga project		<b>17</b>	15
Holding companies for Westside projects		<b>13</b>	13
Holding companies of other unconsolidated operating projects		<b>5</b>	1
<b>Total Distributions</b>		<b>\$ 367</b>	\$ 175

(1) On October 24, 2005, EME received a \$160 million distribution from Midwest Generation.

(2) On October 3, 2005, EME received a \$24 million distribution from Homer City.

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

### ***Intercompany Tax-Allocation Agreement***

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

## Dividend Restrictions in Major Financings

### *General*

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

### *Key Ratios of EME's Principal Subsidiaries Affecting Dividends*

Set forth below are key ratios of EME's principal subsidiaries required by financing arrangements for the twelve months ended September 30, 2005:

<b>Subsidiary</b>	<b>Financial Ratio</b>	<b>Covenant</b>	<b>Actual</b>
Midwest Generation, LLC (Illinois plants)	Interest Coverage Ratio	Greater than or equal to 1.25 to 1	2.35 to 1
Midwest Generation, LLC (Illinois plants)	Secured Leverage Ratio	Less than or equal to 8.75 to 1	3.06 to 1
EME Homer City Generation L.P. (Homer City facilities)	Senior Rent Service Coverage Ratio	Greater than 1.7 to 1	3.03 to 1
Edison Mission Energy Funding Corp. (Big 4 Projects)	Debt Service Coverage Ratio	Greater than or equal to 1.25 to 1	3.14 to 1

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 "MEHC: Liquidity—Dividend Restrictions in Major Financings" in the year-ended 2004 MD&A.

### **MEHC's Interest Coverage Ratio**

The following details with respect to MEHC's interest coverage ratio are provided as an aid to understanding the computations set forth in the indenture governing MEHC's senior secured notes. This information is not intended to measure the financial performance of MEHC and, accordingly, should not be read in lieu of the financial information set forth in MEHC's consolidated financial statements. The terms Funds Flow from Operations, Operating Cash Flow and Interest Expense are as defined in the indenture and are not the same as would be determined in accordance with generally accepted accounting principles.

MEHC's interest coverage ratio equals Funds Flow from Operations divided by Interest Expense and is comprised of interest income and expense related to its holding company activities and the consolidated financial information of EME. The following table sets forth MEHC's interest coverage ratio for the twelve months ended September 30, 2005:

In millions	September 30, 2005
<b>Funds Flow from Operations:</b>	
Operating Cash Flow <sup>(1)</sup> from Consolidated Operating Projects <sup>(2)</sup> :	
Illinois plants	\$ 366
Homer City	121
First Hydro	25
Other consolidated operating projects	3
Price risk management and energy trading	121
Distributions from unconsolidated Big 4 projects	121
Distributions from other unconsolidated operating projects	79
Interest income	38
Operating expenses	(118)
<b>Total EME funds flow from operations</b>	<b>\$ 756</b>
Operating cash flow from unrestricted subsidiaries	1
Funds flow from operations of projects sold	(30)
MEHC (parent)	(2)
<b>Total funds flow from operations</b>	<b>\$ 725</b>
<b>Interest Expense:</b>	
EME	\$ 262
EME – affiliate debt	2
MEHC (parent) interest expense	120
Interest savings on projects sold	(29)
<b>Total interest expense</b>	<b>\$ 355</b>
<b>Interest Coverage Ratio</b>	<b>2.04</b>

(1) Operating cash flow is defined as revenue less operating expenses, foreign taxes paid and project debt service. Operating cash flow does not include capital expenditures or the difference between cash payments under EME's long-term leases and lease expenses recorded in EME's income statement. EME expects its cash payments under its long-term power plant leases to be higher than its lease expense through 2014.

(2) Consolidated operating projects are entities of which EME owns more than a 50% interest and, thus, include the operating results and cash flows in its consolidated financial statements. Unconsolidated operating projects are entities of which EME owns 50% or less and which EME accounts for on the equity method or EME is not the primary beneficiary under an accounting interpretation for variable interest entities.

The above interest coverage ratio was determined in accordance with the definitions set forth in the indenture governing MEHC's senior secured notes. The provisions of the indenture permit MEHC, EME and its subsidiaries to incur additional indebtedness, if, after giving effect to the incurrence of such indebtedness, MEHC's interest coverage ratio exceeds 2.0 to 1 for the immediately preceding four fiscal quarters, or if such additional indebtedness is permitted debt as specified in the indenture. In addition, MEHC is permitted to make dividend if, after giving effect to the dividend, MEHC's interest coverage ratio exceeds 2.0 to 1 for the immediately preceding four fiscal quarters, subject to certain additional conditions and the limits specified in the indenture.

## **MEHC: MARKET RISK EXPOSURES**

### **Introduction**

EME's primary market risk exposures are associated with the sale of electricity and capacity from and the procurement of fuel for its uncontracted generating plants. These market risks arise from fluctuations in electricity, capacity and fuel prices, emission allowances, transmission rights, and interest rates. EME manages these risks in part by using derivative financial instruments in accordance with established policies and procedures. See "MEHC: Current Developments and "MEHC: Liquidity—EME's Credit Ratings," as well as "Critical Accounting Policies and Estimates" in the year-ended 2004 MD&A for a discussion of market developments and their impact on EME's credit and the credit of its counterparties.

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

- Commodity Price Risk
- Credit Risk
- Interest Rate Risk
- Fair Value of Financial Instruments

### **Commodity Price Risk**

#### *General Overview*

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

- prevailing market prices for coal, natural gas and fuel oil, and associated transportation costs;
- 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;
- transmission congestion in and to each market area and the resulting differences in prices between delivery points;
- the market structure rules to be established for each market area and regulatory developments affecting the market areas;
- the cost and availability of emission credits or allowances;
- the availability, reliability and operation of nuclear generating plants, where applicable, and the extended operation of nuclear generating plants beyond their presently expected dates of decommissioning;
- weather conditions prevailing in surrounding areas from time to time; and
- the rate of electricity usage as a result of factors such as regional economic conditions and the implementation of conservation programs.

A discussion of commodity price risk for the Illinois plants and Homer City facilities is set forth below.

## ***Energy Price Risk – Introduction***

Electric power generated at EME's merchant plants is generally sold into the PJM Interconnection, LLC (PJM) market.

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 tolerance, 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 the 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 from unit to unit.

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

## ***Hedging Strategy***

To reduce its exposure to market risk, EME hedges a portion of its merchant portfolio risk through Edison Mission Marketing & Trading. To the extent that EME does not hedge its merchant portfolio, the unhedged portion will be subject to the risks and benefits of spot market price movements. Hedge transactions are primarily implemented through the use of contracts cleared on the Intercontinental Trading Exchange and the New York Mercantile Exchange. Hedge transactions are also entered into as forward sales to utilities and power marketing companies.

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

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

## ***Energy Price Risk Affecting Sales from the Illinois Plants***

### *Pre-2005 Merchant Sales*

Energy generated at the Illinois plants was historically sold under three power purchase agreements between Midwest Generation and Exelon Generation Company, under which Exelon Generation was obligated to make capacity payments for the plants under contract and energy payments for the energy produced by these plants and taken by Exelon Generation. The power purchase agreements began on December 15, 1999. The capacity payments provided the units under contract with revenue for fixed charges, and the energy payments compensated those units for all, or a portion of, variable costs of production. The three power purchase agreements with Exelon Generation had all been terminated by December 31, 2004.

To the extent that energy and capacity from the Illinois plants was not sold under the power purchase agreements with Exelon Generation, it was sold on a wholesale basis through a combination of bilateral agreements, forward energy sales and spot market sales. Approximately 43% of the energy and capacity sales from the Illinois plants in the first nine months of 2004 were made on a wholesale basis outside of the power purchase agreements.

Prior to May 1, 2004, the primary markets available to Midwest Generation for wholesale sales of electricity from the Illinois plants were direct “wholesale customers” and broker arranged “over-the-counter customers.” Effective May 1, 2004, the transmission system of Commonwealth Edison was placed under the control of PJM as the Northern Illinois control area, and on October 1, 2004, the transmission system of AEP was integrated into PJM, which linked eastern PJM and the Northern Illinois control areas of the PJM system and improved access from the Illinois plants into the broader PJM market. Further, on April 1, 2005, the Midwest Independent Transmission System Operator (MISO) commenced operation, linking the MISO footprint, including Illinois, Wisconsin, Indiana, Michigan, and Ohio, in a locational marginal pricing system similar to that of PJM.

Since the initial expansion of PJM, Midwest Generation sells its power into PJM at spot prices based upon locational marginal pricing and is no longer required to arrange and pay separately for transmission when making sales to wholesale buyers within the PJM system. Hedging transactions related to the generation of the Illinois units are entered into at the Northern Illinois Hub in PJM, the AEP/Dayton Hub in PJM and, with the advent of MISO, at the Cinergy Hub in MISO. Because of proximity, the Midwest Generation assets are primarily hedged with transactions at the Northern Illinois Hub, but from time to time may be hedged in limited amounts at the AEP/Dayton Hub and the Cinergy Hub. These trading hubs have been the most liquid locations for these hedging purposes. However, hedging transactions which settle at points other than the Northern Illinois Hub are subject to the possibility of basis risk. See “—Basis Risk” below for further discussion.

Following the expansion of the PJM system described above, sales into the expanded PJM, the primary market currently available to the Illinois plants, replaced sales previously made as bilateral sales and spot sales “Into ComEd” and “Into AEP.” See “MEHC: Other Development—Regulatory Matters” in the year-ended 2004 MD&A for a more detailed discussion of developments regarding Commonwealth Edison’s joining PJM, and “—Basis Risk” below for a discussion of locational marginal pricing.

### *2005 Merchant Sales*

During 2005, electric power generated at the Illinois plants has generally been sold into the PJM market. The PJM pool has a short-term market, which establishes an hourly clearing price. The Illinois plants are situated in the new expanded western PJM control area and are physically connected to high-voltage transmission lines serving this market.

The following table depicts the average historical market prices for energy per megawatt-hour during the first nine months of 2005 and 2004.

	2005 <sup>(1)</sup>	2004
January	\$ 38.36	\$ 27.88 <sup>(2)</sup>
February	34.92	29.98 <sup>(2)</sup>
March	45.75	30.66 <sup>(2)</sup>
April	38.98	27.88 <sup>(2)</sup>
May	33.60	34.05 <sup>(1)</sup>
June	42.45	28.58 <sup>(1)</sup>
July	50.87	30.92 <sup>(1)</sup>
August	60.09	26.31 <sup>(1)</sup>
September	53.30	27.98 <sup>(1)</sup>
Nine-Month Average	\$ 44.26	\$ 29.36

- (1) Represents average historical market prices for energy as quoted for sales into the Northern Illinois Hub. Energy prices were calculated at the Northern Illinois Hub delivery point using hourly real-time prices as published by PJM.
- (2) Represents average historical market prices for energy for “Into ComEd.” Energy prices were determined by obtaining broker quotes and other public price sources for “Into ComEd” delivery points. See discussion under “—Pre-2005 Merchant Sales” above for further discussion regarding the replacement of sales “Into ComEd” with sales into the expanded 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 is affected by weather and economic growth, 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 September 30, 2005:

2005	24-Hour Northern Illinois Hub Forward Energy Prices*
October	\$ 47.40
November	49.98
December	55.85
<b>2006 Calendar “strip”<sup>(1)</sup></b>	<b>\$ 52.74</b>
<b>2007 Calendar “strip”<sup>(1)</sup></b>	<b>\$ 47.61</b>

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

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

The following table summarizes Midwest Generation's hedge position (primarily based on prices at the Northern Illinois Hub) at September 30, 2005:

	2005	2006	2007
Megawatt hours	<b>4,835,118</b>	14,193,014	6,804,000
Average price/MWh <sup>(1)</sup>	<b>\$ 35.34</b>	\$ 43.02	\$ 42.24

- (1) The above hedge positions include forward contracts for the sale of power during different periods of the year and the day. Market prices tend to be higher during on-peak periods during the day and during summer months, although there is significant variability of power prices during different periods of time. Accordingly, the above hedge position at September 30, 2005 is not directly comparable to the 24-hour Northern Illinois Hub prices set forth above.

### *Energy Price Risk Affecting Sales from the Homer City Facilities*

Electric power generated at the Homer City facilities is generally sold into the PJM market. The PJM pool has short-term markets, which establish 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 New York Independent System Operator (NYISO) markets.

The following table depicts the average historical market prices for energy per megawatt-hour in PJM during the first nine months of 2005 and 2004:

	Historical Energy Prices*			
	24-Hour PJM			
	Homer City		West Hub	
	2005	2004	2005	2004
January	\$ 45.82	\$ 51.12	\$ 49.53	\$ 55.01
February	39.40	47.19	42.05	44.22
March	47.42	39.54	49.97	39.21
April	44.27	43.01	44.55	42.81
May	43.67	44.68	43.64	48.04
June	46.63	36.72	53.72	38.05
July	54.63	40.09	66.34	43.64
August	66.39	34.76	82.83	38.59
September	66.67	40.62	76.82	41.96
Nine-Month Average	\$ 50.54	\$ 41.97	\$ 56.61	\$ 43.50

- \* 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-ISO 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 is affected by weather and economic growth, 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 September 30, 2005:

<b>2005</b>	<b>24-Hour PJM West Hub Forward Energy Prices*</b>
October	69.90
November	74.49
December	80.80
<b>2006 Calendar “strip”<sup>(1)</sup></b>	<b>\$ 72.01</b>
<b>2007 Calendar “strip”<sup>(1)</sup></b>	<b>\$ 62.18</b>

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

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

The following table summarizes Homer City’s hedge position at September 30, 2005:

	<b>2005</b>	2006	2007
Megawatt hours	<b>2,215,125</b>	8,525,200	3,618,000
Average price/MWh <sup>(1)</sup>	<b>\$ 43.14</b>	\$ 53.24	\$ 60.68

(1) The above hedge positions include forward contracts for the sale of power during different periods of the year and the day. Market prices tend to be higher during on-peak periods during the day and during summer months, although there is significant variability of power prices during different periods of time. Accordingly, the above hedge position at September 30, 2005 is not directly comparable to the 24-hour PJM West Hub prices set forth above.

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

### ***Basis Risk***

Sales made from the Illinois plants and the Homer City facilities in the real-time or day-ahead market receive the actual spot prices 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, there is not a liquid market for entering into these contracts at the individual plant busbars. A liquid market does exist for a settlement point known as the PJM West Hub in the case of Homer City and for a settlement point known as the Northern Illinois Hub in the case of the Illinois plants. EME’s price risk management activities use these settlement points (and, to a lesser extent, other similar trading hubs) to enter into hedging contracts. EME’s revenue with respect to such forward contracts include:

- sales of actual generation in the amounts covered by such 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 Homer City and the Northern Illinois Hub for the Illinois plants) less the cost of power at spot prices at the same designated settlement points.

Under the PJM market design, locational marginal pricing (sometimes referred to as LMP), which establishes hourly 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 raised or lowered relative to other locations depending on how the point is affected by transmission constraints. To the extent that, on the settlement date of a hedge contract, spot prices at the relevant busbar are lower than spot prices at the settlement point, the proceeds actually realized from the related hedge contract are effectively reduced by the difference. This is referred to by EME as “basis risk.” During the past 12 months, transmission congestion in PJM has resulted in prices at the Homer City busbar being lower than those at the PJM West Hub (the primary trading hub in PJM for the Homer City facilities) by an average of 9%. The monthly average difference during this period ranged from zero to 20%, which occurred in August 2005. For comparison, the same difference during 2004 was 4%. By contrast to the Homer City facilities, during the past 12 months, transmission congestion in PJM has not resulted in prices at the Northern Illinois Hub being significantly different from those at the individual busbars of the Illinois plants.

By entering into cash settled future contracts and forward contracts using the PJM West Hub and the Northern Illinois Hub (or other similar trading hubs) as the settlement points, EME is exposed to basis risk as described above. In order to mitigate basis risk, EME has participated in purchasing financial transmission rights in PJM, and may continue to do so in the future. A financial transmission right is a financial instrument that entitles the holder thereof to receive actual spot prices at one point of delivery and pay prices at another point of delivery that are pegged to prices at the first point of delivery, plus or minus a fixed amount. Accordingly, EME’s price risk management activities include using financial transmission rights alone or in combination with forward contracts to manage basis risk.

### ***Coal Price and Transportation Risk***

The Illinois plants use approximately 18 million to 20 million tons of coal annually, primarily obtained from the Southern Powder River Basin of Wyoming. In addition, the Homer City facilities use approximately 5 million tons of coal annually, obtained from mines located near the facilities in Pennsylvania. Coal purchases are made under a variety of supply agreements typically ranging from one year to six years in length. The following table summarizes the percent of expected coal requirements for the next five years that are under contract at September 30, 2005.

	<b>Percent of Coal Requirements Under Contract</b>				
	<b>2005<sup>(1)</sup></b>	<b>2006</b>	<b>2007</b>	<b>2008</b>	<b>2009</b>
Illinois plants	111%	100%	91%	32%	32%
Homer City facilities <sup>(2)</sup>	101%	78%	78%	21%	15%

- (1) The percentage in 2005 is calculated based on coal supply and expected generation requirements for a full year.
- (2) Adjusted for expected deliveries under an executed agreement to settle outstanding contract disputes. See “Commitments, Guarantees and Indemnities—Fuel Supply Contracts” for more information regarding fuel supply interruptions and the dispute with two suppliers.

EME is subject to price risk for purchases of coal that are not under contract. Prices of Northern Appalachia coal, which is purchased for the Homer City facilities, increased considerably since 2004. In January 2004, prices of Northern Appalachia coal (with 13,000 British Thermal units (Btu) content and <3.0 SO2 MMBtu content) were below \$40 per ton and increased to more than \$60 per ton during 2004. On September 30, 2005, the Energy Information Administration reported the price of Northern Appalachia coal at \$54.00 per ton. The overall increase in the Northern Appalachia coal price has been largely attributed to greater demand from domestic power producers and increased international

shipments of coal to Asia. Prices of Powder River Basin (PRB) coal (with 8,800 Btu content and 0.8 SO<sub>2</sub> MMBtu content), which is purchased for the Illinois plants, have recently increased due to curtailment of coal shipments for the remainder of 2005 due to increased PRB coal demand from the other regions (east), rail constraints (discussed below) and higher prices for SO<sub>2</sub> allowances. On September 30, 2005, the Energy Information Administration reported the price of \$12.79 per ton, which compares to 2004 prices generally below \$7 per ton.

During the first nine months of 2005, the rail lines that bring coal from the PRB to EME's Illinois plants were damaged from derailments caused by heavy rains. The railroads are in the process of making repairs to these rail lines and have advised their customers, including EME, that shipments will be curtailed by 15% to 20% during 2005. Through September 30, 2005, EME received approximately 87% of expected shipments and expects to receive shipments of approximately 80% to 85% during the fourth quarter of 2005. Rail maintenance will continue as long as weather permits. EME continues to work with its transportation provider to minimize any disruption of planned shipments. Based on communication with the transportation provider, EME expects to continue receiving a sufficient amount of coal to generate power at historical levels while these repairs are being completed.

### ***Emission Allowances Price Risk***

Under the federal Acid Rain Program (which requires electric generating stations to hold sulfur dioxide allowances) and Illinois and Pennsylvania regulations implementing the federal NO<sub>x</sub> SIP Call requirement, EME purchases (or sells) emission allowances based on the amounts required for actual generation in excess of (or less than) the amounts allocated under these programs. As part of the acquisition of the Illinois plants and the Homer City facilities, EME obtained the rights to the emission allowances that have been or are allocated to these plants.

The price of emission allowances, particularly SO<sub>2</sub> allowances issued through the United States EPA Acid Rain Program, increased substantially during 2004 and the first nine months of 2005. The average price of purchased SO<sub>2</sub> allowances increased to \$765 per ton during the nine months ended September 30, 2005 from \$281 per ton during the nine months ended September 30, 2004. The increase in the price of SO<sub>2</sub> allowances has been attributed to reduced numbers of both allowance sellers and prior vintage allowances.

### **Credit Risk**

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

To manage credit risk, EME looks at the risk of a potential default by counterparties. Credit risk is measured by the loss that would be incurred if counterparties failed to perform pursuant to the terms of their contractual obligations. EME measures, monitors and mitigates, to the extent possible, credit risk. To mitigate counterparty risk, master netting agreements are used whenever possible and counterparties may be required to pledge collateral when deemed necessary. EME also takes other appropriate steps to limit or lower credit exposure. Processes have also been established to determine and monitor the creditworthiness of counterparties. EME manages the credit risk on the portfolio based on credit ratings using published ratings of counterparties and other publicly disclosed information, such as financial statements, regulatory filings, and press releases, to guide it in the process of setting credit levels, risk limits and contractual arrangements, including master netting agreements. A risk management committee

regularly reviews the credit quality of EME's counterparties. Despite this, there can be no assurance that these efforts will be wholly successful in mitigating credit risk or that collateral pledged will be adequate.

EME measures credit risk exposure from counterparties of its merchant energy activities as either: (i) the sum of 60 days of accounts receivable, current fair value of open positions, and a credit value at risk, or (ii) the sum of delivered and unpaid accounts receivable and the current fair value of open positions. EME's subsidiaries enter into master agreements and other arrangements in conducting price risk management and trading activities which typically provide for a right of setoff in the event of bankruptcy or default by the counterparty. Accordingly, EME's credit risk exposure from counterparties is based on net exposure under these agreements. At September 30, 2005, the amount of exposure, broken down by the credit ratings of EME's counterparties, was as follows:

In millions	<b>September 30, 2005</b>
<b>S&amp;P Credit Rating</b>	
A or higher	\$ 2
A-	148
BBB+	64
BBB	3
BBB-	1
Below investment grade	—
<b>Total</b>	<b>\$ 218</b>

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

In addition, coal for the Illinois plants and the Homer City facilities is purchased from suppliers under contracts which may be for multiple years. A number of the coal suppliers to the Illinois plants and the Homer City facilities do not currently have an investment grade credit rating and, accordingly, EME may have limited recourse to collect damages from a supplier in the event of default. 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.

For the nine months ended September 30, 2004, one customer accounted for 14% and a second customer, Exelon Generation, accounted for 40% of EME's consolidated operating revenue. For more information on Exelon Generation, see "—Commodity Price Risk—Energy Price Risk Affecting Sales from the Illinois Plants—Pre-2005 Merchant Sales."

### **Interest Rate Risk**

Interest rate changes affect the cost of capital needed to operate EME's projects. EME mitigates the risk of interest rate fluctuations by arranging for fixed rate financing or variable rate financing with interest rate swaps, interest rate options or other hedging mechanisms for a number of 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 MEHC's total long-term obligations (including current portion) was \$4.7 billion at September 30, 2005, compared to the carrying value of \$4.1 billion. The fair market value of MEHC's parent only total long-term obligations was \$961 million at September 30, 2005, compared to the carrying value of \$791 million.

## Fair Value of Financial Instruments

### *Non-Trading Derivative Financial Instruments*

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

In millions	September 30, 2005	December 31, 2004
Commodity price:		
Electricity	\$ (582)	\$ 10

In assessing the fair value of EME's non-trading derivative financial instruments, EME uses a variety of methods and assumptions based on the market conditions and associated risks existing at each balance sheet date. The fair value of commodity price contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities and other factors. The following table summarizes the maturities, the valuation method and the related fair value of EME's commodity price risk management assets and liabilities as of September 30, 2005:

In millions	Total Fair Value	Maturity Less than 1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity Greater than 5 years
Prices actively quoted	\$(582)	\$ (501)	\$(81)	\$ —	\$ —

### *Energy Trading Derivative Financial Instruments*

The fair value of the commodity financial instruments related to energy trading activities as of September 30, 2005 and December 31, 2004, are set forth below:

In millions	September 30, 2005		December 31, 2004	
	Assets	Liabilities	Assets	Liabilities
Electricity	\$ 186	\$ 79	\$ 125	\$ 36

The change in the fair value of trading contracts for the nine months ended September 30, 2005, was as follows:

In millions	
Fair value of trading contracts at January 1, 2005	\$ 89
Net gains from energy trading activities	130
Amount realized from energy trading activities	(130)
Other changes in fair value	18
Fair value of trading contracts at September 30, 2005	\$ 107

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

summarizes the maturities, the valuation method and the related fair value of energy trading assets and liabilities (as of September 30, 2005):

In millions	<b>Total Fair Value</b>	<b>Maturity Less than 1 year</b>	<b>Maturity 1 to 3 years</b>	<b>Maturity 4 to 5 years</b>	<b>Maturity Greater than 5 years</b>
Prices actively quoted	\$ 18	\$ 18	\$ —	\$ —	\$ —
Prices based on models and other valuation methods	89	2	9	7	71
<b>Total</b>	<b>\$ 107</b>	<b>\$ 20</b>	<b>\$ 9</b>	<b>\$ 7</b>	<b>\$ 71</b>

## **MEHC: OTHER DEVELOPMENTS**

### **Agreement to Sell the Doga Project**

EME owns an 80% interest in a 180 MW gas-fired cogeneration plant near Istanbul, Turkey, which EME refers to as the Doga project. On August 17, 2005, EME entered into a purchase agreement to sell its interest in the Doga project to EME's co-investor in the Doga project, Doga Enerji Yatirim Isletme ve Ticaret Limited Sirketi, which will acquire an additional 30% interest in the Doga project, and The Kansai Electric Power Co., Inc., which will acquire a 50% interest in the Doga project. Completion of the sale is subject to the satisfaction of a number of closing conditions, including obtaining the consent of a majority of the project's lenders. The sale is expected to close in the fourth quarter of 2005.

### **Regulatory Matters**

There have been no significant developments with respect to regulatory matters specifically affecting EME since the filing of MEHC's annual report, except as follows:

The MISO's day-ahead and real-time locational marginal pricing markets commenced operation on April 1, 2005. Since that time, the wholesale electricity trading community has opted to trade a product delivered at the Cinergy Hub as defined by MISO rather than at the "Into Cinergy" location that was used previously. EME anticipates that the opening of the MISO market will lead to increased liquidity in the Midwest electricity markets because locational marginal pricing provides a liquid and credible cash index against which the trading community can settle contracts.

## **EDISON CAPITAL**

### **EDISON CAPITAL: LIQUIDITY**

Edison Capital's main sources of liquidity are tax-allocation payments from Edison International, distributions from its global infrastructure fund investments and lease rents. During the nine months ended September 30, 2005, Edison Capital received \$163 million in tax-allocation payments, \$98 million in global infrastructure fund distributions and \$13 million in lease rent payments.

Edison Capital's cash requirements during the twelve-month period following September 30, 2005, are expected to primarily consist of:

- Funding investments in renewable energy;
- Scheduled debt principal and interest payments; and
- General and administrative expenses.

As of September 30, 2005, Edison Capital had unrestricted cash and cash equivalents of \$354 million and long-term debt, including current maturities, of \$299 million.

Edison Capital expects to meet its operating cash needs through cash on hand, tax-allocation payments from Edison International (parent) and expected cash flow from operating activities.

At September 30, 2005, Edison Capital's long-term debt had credit ratings of Ba1 and BB+ from Moody's Investors Service and Standard & Poor's, respectively.

Edison Capital has an existing 196 MW portfolio of wind projects located in Iowa and Minnesota. In addition, a subsidiary of Edison Capital has entered into an agreement to acquire a 120 MW wind project in eastern New Mexico from a wind generation developer for \$157 million. The acquisition of this project is subject to substantial completion of construction and other closing conditions which are expected to be met in December 2005. EME and Edison Capital are considering transferring some or all of these projects to EME as part of its independent power generation portfolio and to expand significantly through EME further investments in wind projects throughout the United States.

### **EDISON CAPITAL: MARKET RISK EXPOSURES**

Edison Capital is exposed to interest rate risk, foreign currency exchange rate risk and credit and performance risk that could adversely affect its results of operations or financial position. See "Edison Capital: Market Risk Exposures" in the year-ended 2004 MD&A for a complete discussion of Edison Capital's market risk exposures.

### **EDISON CAPITAL: OTHER DEVELOPMENT**

#### **Federal Income Taxes**

Edison International received Revenue Agent Reports from the Internal Revenue Service (IRS) in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994–1996 and 1997–1999 tax years, respectively. Among the issues raised were items related to Edison Capital. See "Other Developments—Federal Income Taxes" for further discussion of these matters.

## EDISON INTERNATIONAL (PARENT)

### EDISON INTERNATIONAL (PARENT): LIQUIDITY

The parent company's liquidity and its ability to pay interest, debt principal, operating expenses and dividends to common shareholders are affected by dividends from subsidiaries, tax-allocation payments under its tax-allocation agreements with its subsidiaries, and access to capital markets or external financings. Edison International was focused on reducing its parent company debt in 2004, and as of September 30, 2005, had no debt outstanding.

Edison International (parent)'s 2005 cash requirements primarily consist of:

- Dividends to common shareholders. The Board of Directors of Edison International declared a \$0.25 per share quarterly common stock dividend in the first, second and third quarters of 2005. The \$81 million quarterly common stock dividends were paid on each of May 3, 2005, August 1, 2005 and October 31, 2005, respectively; and
- General and administrative expenses.

Edison International (parent) expects to meet its continuing obligations through cash and cash equivalents on hand, short-term borrowings, when necessary, and dividends from its subsidiaries. At September 30, 2005, Edison International (parent) had approximately \$135 million of cash and cash equivalents on hand. In February 2005, Edison International (parent) entered into a \$750 million senior unsecured 5-year revolving credit facility and as of September 30, 2005, the entire \$750 million was available under the credit facility. The ability of subsidiaries to make dividend payments to Edison International is dependent on various factors as described below.

The CPUC regulates SCE's capital structure by requiring that SCE maintain prescribed percentages of common equity, preferred equity and long-term debt in the utility's capital structure. SCE may not make any distributions to Edison International that would reduce the common equity component of SCE's capital structure below the prescribed level on a 13-month weighted average basis. The CPUC also requires that SCE establish its dividend policy as though it were a comparable stand-alone utility company and give first priority to the capital requirements of the utility as necessary to meet its obligation to serve its customers. Other factors at SCE that affect the amount and timing of dividend payments by SCE to Edison International include, among other things, SCE's cash requirements, SCE's access to capital markets, dividends on SCE's preferred and preference stock, and actions by the CPUC. SCE made dividend payments of \$71 million to Edison International on each of April 28, 2005, July 28, 2005, and September 30, 2005.

MEHC may not pay dividends unless it has an interest coverage ratio of at least 2.0 to 1. At September 30, 2005, its interest coverage ratio was 2.04 to 1. See "MEHC: Liquidity—MEHC's Interest Coverage Ratio." In addition, MEHC's certificate of incorporation and senior secured note indenture contain restrictions on MEHC's ability to declare or pay dividends or distributions (other than dividends payable solely in MEHC's common stock). These restrictions require the unanimous approval of MEHC's Board of Directors, including its independent director, before it can declare or pay dividends or distributions, as long as any indebtedness is outstanding under the indenture. MEHC's ability to pay dividends is dependent on EME's ability to pay dividends to MEHC (parent). MEHC has not declared or made dividend payments to Edison International in 2005. EME and its subsidiaries have certain dividend restrictions as discussed in the "MEHC: Liquidity—Dividend Restrictions in Major Financings" section.

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

September 30, 2005. Edison Capital has not declared or made dividend payments to Edison International in 2005.

### **EDISON INTERNATIONAL (PARENT): MARKET RISK EXPOSURES**

Although Edison International (parent) had no debt outstanding as of September 30, 2005, the parent company may be exposed to changes in interest rates which may result from future borrowing and investing activities. The proceeds of such borrowings and investing activities may be used for general corporate purposes, including investments in nonutility businesses. The nature and amount of the parent company's long-term and short-term debt can be expected to vary as a result of future business requirements, market conditions and other factors.

### **EDISON INTERNATIONAL (PARENT): OTHER DEVELOPMENTS**

#### **Holding Company Proceeding**

Edison International was a party to a CPUC holding company proceeding that closed in May 2005. On October 27, 2005, the CPUC issued an order instituting rulemaking to allow the CPUC to re-examine the relationships of the major California energy utilities with their parent holding companies and non-regulated affiliates. See "SCE: Regulatory Matters—Other Regulatory Matters—Holding Company Proceeding and Order Instituting Rulemaking" for a discussion of these matters.

#### **Federal Income Taxes**

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994–1996 and 1997–1999 tax years, respectively. See "Other Developments—Federal Income Taxes" for further discussion of these matters.

## EDISON INTERNATIONAL (CONSOLIDATED)

The following sections of the MD&A are on a consolidated basis. The section begins with a discussion of Edison International's consolidated results of operations and historical cash flow analysis. This is followed by discussions of discontinued operations, new and proposed accounting principles, commitments, guarantees and indemnities, and other developments.

### RESULTS OF OPERATIONS AND HISTORICAL CASH FLOW ANALYSIS

The following subsections of "Results of Operations and Historical Cash Flow Analysis" provide a discussion on the changes in various line items presented on the Consolidated Statements of Income as well as a discussion of the changes on the Consolidated Statements of Cash Flows.

#### Results of Operations

Edison International recorded consolidated earnings of \$462 million, or \$1.41 per common share for the three-month period ended September 30, 2005, compared with consolidated earnings of \$813 million or \$2.49 per common share for the three-month period ended September 30, 2004. The decrease is primarily due to the impacts from the sale of MEHC's international assets in 2004 reported as discontinued operations. The decrease was partially offset by improved operating results at MEHC from higher wholesale energy prices, higher energy trading income and lower net interest expense.

Edison International recorded consolidated earnings of \$864 million, or \$2.64 per common share for the nine-month period ended September 30, 2005, compared to consolidated earnings of \$537 million or \$1.65 per common share for the same period in 2004. The increase reflects higher wholesale energy prices and higher energy trading income at MEHC, lower net interest expense, higher net revenue and tax items at SCE, gains from Edison Capital's Emerging Europe Infrastructure Fund, and a loss recorded in 2004 on the termination of MEHC's Collins Station lease. These increases were partially offset by the impacts from the sale of MEHC's international assets in 2004 reported as discontinued operations, as well as net positive regulatory adjustments recorded in 2004 related to the implementation of SCE's 2003 GRC decision.

The tables below present Edison International's earnings and earnings per common share for the three- and nine-month periods ended September 30, 2005 and 2004, and the relative contributions by its subsidiaries.

In millions, except per common share amounts	Earnings (Loss)		Earnings (Loss) per Common Share	
Three-Month Period Ended September 30,	2005	2004	2005	2004
Earnings (Loss) from Continuing Operations:				
SCE	\$ 280	\$ 259	\$ 0.86	\$ 0.79
MEHC	154	60	0.48	0.18
Edison Capital	3	12	0.01	0.04
Edison International (parent) and other	(2)	(17)	(0.02)	(0.05)
<hr/>				
Edison International Consolidated Earnings (Loss) from Continuing Operations	435	314	1.33	0.96
Earnings from Discontinued Operations	27	499	0.08	1.53
<b>Edison International Consolidated</b>	<b>\$ 462</b>	<b>\$ 813</b>	<b>\$ 1.41</b>	<b>\$ 2.49</b>

In millions, except per common share amounts	Earnings (Loss)		Earnings (Loss) per Common Share	
Nine-Month Period Ended September 30,	2005	2004	2005	2004
Earnings (Loss) from Continuing Operations:				
SCE	\$ 572	\$ 600	\$ 1.75	\$ 1.84
MEHC	179	(614)	0.55	(1.88)
Edison Capital	80	34	0.25	0.11
Edison International (parent) and other	(22)	(52)	(0.08)	(0.17)
Edison International Consolidated Earnings (Loss) from Continuing Operations	809	(32)	2.47	(0.10)
Earnings from Discontinued Operations	55	570	0.17	1.75
Cumulative Effect of Accounting Change	—	(1)	—	—
Edison International Consolidated	\$ 864	\$ 537	\$ 2.64	\$ 1.65

### *Earnings from Continuing Operations*

SCE's earnings from continuing operations were \$280 million and \$572 million for the three- and nine-month periods ended September 30, 2005, respectively, compared to \$259 million and \$600 million for the same periods in 2004. SCE's earnings reflect a positive tax item of \$61 million related to a favorable tax settlement (see "Other Developments—Federal Income Taxes) for both periods in 2005, as well as net positive regulatory adjustments of \$50 million and \$172 million for the three- and nine-month periods ended September 30, 2004, respectively, primarily from the implementation of SCE's 2003 GRC decision. The increases for both periods were due to higher net revenue for 2005 and a tax benefit from a new IRS regulation. The quarter increase was partially offset by the expected timing difference related to the implementation of the 2003 GRC decision in July 2004. The year-to-date increase was further increased by the favorable resolution of tax issues.

MEHC's earnings from continuing operations were \$154 million and \$179 million for the three- and nine-months ended September 30, 2005, respectively, compared to \$60 million and a loss of \$614 million for the same periods in 2004, respectively. MEHC's 2005 earnings reflect an impairment charge of \$34 million recorded in the third quarter of 2005, related to MEHC's March Point project as the rise in forecast fuel costs lowered projected cash flows. In addition, the year-to-date 2005 earnings reflect a \$15 million charge related to early debt retirements. MEHC's 2004 earnings include charges of \$18 million recorded in the third quarter of 2004, primarily from an impairment related to Midwest Generation's small peaking plants. In addition, the year-to-date 2004 earnings include a \$590 million charge for the termination of the Collins Station lease, a net gain of \$27 million on the sale of MEHC's interest in Four Star Oil & Gas and the Brooklyn Navy Yard projects, and an \$18 million charge related to a peaker impairment. The increase for the three- and nine-month periods ended September 30, 2005, as compared to the same periods in 2004, were primarily due to higher wholesale energy prices, higher energy trading income and lower net interest expense.

Earnings in the third quarter of 2005 for Edison Capital were \$3 million and \$80 million for the three- and nine-month periods ended September 30, 2005, respectively, compared to \$12 million and \$34 million for the same periods in 2004, respectively. The three-month period decrease reflects lower income from Edison Capital's investment in the Emerging Europe Infrastructure Fund. The nine-month period increase is primarily due to gains on Edison Capital's investment in the Emerging Europe Infrastructure Fund.

The loss for "Edison International parent company and other" decreased by \$15 million and \$30 million for the three- and nine-month periods ended September 30, 2005, respectively, as compared to the same periods in 2004, primarily due to lower net interest expense.

## ***Operating Revenue***

SCE's retail sales represented approximately 85% and 83% of electric utility revenue for the three- and nine-month periods ended September 30, 2005, respectively, compared to approximately 88% and 86% of electric utility revenue for the three- and nine-month periods ended September 30, 2004, respectively. Due to warmer weather during the summer months, electric utility revenue during the third quarter of each year is generally significantly higher than other quarters.

The following table sets forth the major changes in electric utility revenue:

In millions	Three-Month Period Ended September 30, 2005 vs. 2004	Nine-Month Period Ended September 30, 2005 vs. 2004
<b>Electric utility revenue</b>		
Rate changes (including unbilled)	\$ 316	\$ 497
Sales volume changes (including unbilled)	190	352
Deferred revenue	(200)	(473)
Sales for resale	90	134
SCE's variable interest entities	20	129
Other (including intercompany transactions)	13	28
<b>Total</b>	<b>\$ 429</b>	<b>\$ 667</b>

Total electric utility revenue increased by \$429 million and \$667 million for the three- and nine-month periods ended September 30, 2005, respectively (as shown in the table above), as compared to the same periods in 2004. The variance in electric utility revenue from rate changes reflects the implementation of the 2003 GRC, effective in August 2004. As a result, generation rates increased revenue by approximately \$295 million and \$235 million for the three- and nine-month periods ended September 30, 2005, respectively, and distribution rates increased revenue by approximately \$20 million and \$260 million for the three- and nine-month periods ended September 30, 2005, respectively. The change in deferred revenue reflects the deferral of approximately \$90 million and \$290 million of revenue in the three- and nine-month periods ended September 30, 2005, respectively, resulting from balancing account overcollections, compared to the recognition of approximately \$110 million and \$180 million of deferred revenue in the three- and nine-month periods ended September 30, 2004, respectively. The increase in electric utility revenue resulting from sales volume changes was mainly due to an increase in kWh sold and SCE providing a greater amount of energy to its customers from its own sources in 2005, compared to 2004. Electric utility revenue from sales for resale represents the sale of excess energy. As a result of the CDWR contracts allocated to SCE, excess energy from SCE sources may exist at certain times, which then is resold in the energy markets. SCE's variable interest entities revenue represents the recognition of revenue resulting from the consolidation of SCE's variable interest entities on March 31, 2004.

Amounts SCE bills and collects from its customers for electric power purchased and sold by the CDWR to SCE's customers (beginning January 17, 2001), CDWR bond-related costs (beginning November 15, 2002) and direct access exit fees (beginning January 1, 2003) are remitted to the CDWR and are not recognized as revenue by SCE. These amounts were \$534 million and \$1.5 billion for the three- and nine-month periods ended September 30, 2005, respectively, compared to \$693 million and \$1.9 billion for the same periods in 2004.

Nonutility power generation revenue increased \$168 million and \$348 million for the three- and nine-month periods ended September 30, 2005, respectively, as compared to the same periods in 2004, due to higher energy revenue, higher net gains from price risk management and energy trading activities, partially offset by lower capacity revenue. Energy revenue from MEHC's Illinois plants increased by approximately \$245 million and \$460 million for the three- and nine-month periods ended September 30, 2005, respectively, as compared to the same periods in 2004, due to increased average energy prices.

Energy revenue at MEHC’s Homer City facilities increased by approximately \$55 million and \$110 million for the three- and nine-month periods ended September 30, 2005, respectively, as compared to the same periods in 2004, due to higher average energy prices and increased generation. During the first quarter of 2004, an unplanned outage at MEHC’s Homer City facilities contributed to lower generation. During the third quarter of 2004, coal deliveries under contracts with four fuel suppliers to MEHC’s Homer City facilities were temporarily interrupted. As a result of these interruptions, MEHC’s Homer City facilities reduced generation during off-peak periods when power prices were lower and purchased coal from alternative suppliers at spot prices, which were substantially higher than the contract prices from these four fuel suppliers (see “Commitments, Guarantees, and Indemnities—Fuel Supply Contracts” for further discussion). The increases in energy revenue were partially offset by lower capacity revenue of approximately \$160 million and \$245 million for the three- and nine-month periods ended September 30, 2005, respectively, at MEHC’s Illinois plants from the expiration of the power-purchase agreements with Exelon Generation, as well as a decrease of \$29 million (representing revenue for the first quarter of 2005) due to the deconsolidation of EME’s Doga project at March 31, 2004, in accordance with accounting standards. Net gains (losses) from price risk management and energy trading activities increased approximately \$35 million and \$60 million for the three- and nine-month periods ended September 30, 2005, respectively, as compared to the same periods in 2004. The volatile market conditions during the first nine months of 2005, driven by increased prices for natural gas and oil and warmer summer temperatures, have created favorable conditions for Edison Mission Marketing & Trading’s strategies relative to conditions in 2004. The results of these favorable conditions have been partially offset by losses from price risk management activities at MEHC’s Illinois plants and Homer City facilities.

Due to higher demand for electricity resulting from warmer weather during the summer months, nonutility power generation revenue generated from MEHC’s Illinois plants and Homer City facilities is generally higher during the third quarter of each year. However, as a result of recent increases in market prices for power (driven in part by higher natural gas and oil prices), this historical trend may not be applicable to quarterly revenue in the future.

### *Operating Expenses*

#### *Fuel Expense*

In millions	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
SCE	\$ 296	\$ 254	\$ 817	\$ 550
MEHC	193	161	492	477
Edison International Consolidated	\$ 489	\$ 415	\$ 1,309	\$ 1,027

SCE’s fuel expense increased for the three- and nine-month periods ended September 30, 2005, as compared to the same periods in 2004, mainly due to the consolidation of SCE’s variable interest entities in March 31, 2004. Fuel expense related to SCE’s variable interest entities was approximately \$225 million and \$624 million for the three- and nine-month periods ended September 30, 2005, respectively, compared to approximately \$187 million and \$375 million for the comparable periods in 2004.

MEHC’s fuel expense increased for the three- and nine-month periods ended September 30, 2005, mainly attributable to higher fuel consumption, higher coal prices and higher priced SO<sub>2</sub> emission allowances (see “MEHC: Market Risk Exposures—Commodity Price Risk—Emission Allowances Price Risk” for more information regarding the price of SO<sub>2</sub> allowances). The nine-month period increase was partially offset by lower fuel costs attributable to the cessation of operations at MEHC’s Collins Station effective September 30, 2004.

### *Purchased-Power Expense*

Purchased-power expense decreased \$413 million and \$389 million for the three- and nine-month periods ended September 30, 2005, respectively, as compared to the same periods in 2004. The decreases were mainly due to net realized and unrealized gains on economic hedging transactions and lower ISO-related purchases, partially offset by higher firm energy and QF purchases. Net realized and unrealized gains related to economic hedging transactions, resulting from increased hedging activities, were approximately \$585 million and \$530 million for the three- and nine-month periods ended September 30, 2005, respectively, as compared to net realized and unrealized losses of approximately \$75 million for both periods in 2004. ISO-related purchases decreased approximately \$50 million and \$95 million for the three- and nine-month periods ended September 30, 2005, respectively, as compared to the same periods in 2004. These decreases were partially offset by higher firm energy expenses of approximately \$315 million and \$490 million for the three- and nine-month periods ended September 30, 2005, respectively, as compared to the same periods in 2004, resulting from an increase in the number of bilateral contracts in 2005, as compared to 2004, and higher QF-related purchases of approximately \$30 million and \$70 million for the three- and nine-month periods ended September 30, 2005, respectively, as compared to the same periods in 2004. The nine-month period decrease also reflects approximately \$130 million of energy settlement refunds received in 2005 (see “SCE: Regulatory Matters—Transmission and Distribution—Wholesale Electricity and Natural Gas Markets”), as compared to approximately \$65 million received during the same period in 2004, as well as a reduction of \$205 million in purchased-power resulting from the consolidation of SCE’s variable interest entities on March 31, 2004.

Federal law and CPUC orders required SCE to enter into contracts to purchase power from QFs at CPUC-mandated prices. Energy payments to gas-fired QFs are generally tied to spot natural gas prices. Effective May 2002, energy payments for most renewable QFs were converted to a fixed price of 5.37¢-per-kWh. Average spot natural gas prices were higher during 2005 as compared to 2004. The higher expenses related to power purchased from QFs were mainly due to higher average spot natural gas prices, partially offset by lower kWh purchases.

### *Provisions for Regulatory Adjustment Clauses – Net*

Provisions for regulatory adjustment clauses – net increased \$800 million and \$875 million for the three- and nine-month periods ended September 30, 2005, respectively, as compared to the same periods in 2004. The increases mainly result from higher net unrealized gains on economic hedging transactions, net overcollections related to balancing accounts, lower CEMA-related costs, and GRC regulatory adjustments. The quarter and year-to-date increases reflect higher net unrealized gains of approximately \$575 million and \$525 million for the three- and nine-month periods ended September 30, 2005, respectively, related to economic hedging transactions (mentioned above in purchased-power expense) that, if realized, would be refunded to ratepayers; net overcollections of purchased power, fuel, and operating and maintenance expenses of approximately \$180 million and \$45 million for the three- and nine-month periods ended September 30, 2005 which were deferred in balancing accounts for future recovery; lower costs incurred and deferred (approximately \$25 million and \$85 million for the three- and nine-month periods ended September 30, 2005, respectively, as compared to the same periods in 2004) associated with CEMA-related costs; and the net effect of regulatory adjustments related to the implementation of SCE’s 2003 GRC decision in the amount of \$180 million recorded in the second quarter of 2004 and approximately \$15 million recorded in the third quarter of 2004. The 2003 GRC regulatory adjustments primarily related to recognition of revenue from the rate recovery of pension contributions during the time period that the pension plan was fully funded, resolution over the allocation of costs between transmission and distribution for 1998 through 2000, partially offset by the deferral of revenue previously collected during the incremental cost incentive pricing mechanism for dry cask storage.

### *Other Operation and Maintenance Expense*

In millions	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
SCE	\$ 668	\$ 606	\$1,835	\$1,760
MEHC	172	170	586	561
Other	22	11	64	46
Edison International Consolidated	\$ 862	\$ 787	\$2,485	\$2,367

SCE's other operation and maintenance expense increased for the three- and nine-month periods ended September 30, 2005, as compared to the same periods in 2004. The increases were mainly due to an increase in reliability costs, demand-side management and energy efficiency costs, and benefit-related costs, partially offset by lower CEMA-related costs and generation-related costs. The quarter and year-to-date increases reflect an increase in reliability costs of approximately \$35 million and \$75 million for the three- and nine-month periods ended September 30, 2005, respectively, as compared to the same periods in 2004, due to an increase in must-run units to improve the reliability of the California ISO systems operations (which are recovered through regulatory mechanisms approved by the FERC); an increase in demand side management and energy efficiency costs of approximately \$25 million and \$50 million for the three- and nine-month periods ended September 30, 2005 in 2005, respectively (which are recovered through regulatory mechanisms approved by the CPUC); and higher benefit-related costs of approximately \$40 million and \$50 million for the three- and nine-month periods ended September 30, 2005, respectively, resulting from an increase in health care costs and value of performance shares. The quarter and year-to-date increases were partially offset by lower CEMA-related costs of approximately \$25 million and \$85 million for the three- and nine-month periods, respectively, compared to the same periods in 2004; and a decrease in generation-related expenses of approximately \$10 million and \$65 million, for the three- and nine-month periods ended September 30, 2005, respectively, as compared to 2004, resulting from lower outage and refueling costs (in 2004, there was a scheduled major overhaul at SCE's Four Corners coal facility, as well as a refueling outage at SCE's San Onofre Unit 2). The year-to-date variance was also due to an increase of approximately \$30 million in O&M expenses as a result of the consolidation of SCE's variable interest entities, as well as higher worker's compensation accruals of approximately \$10 million in 2005 compared to 2004.

MEHC's other operation and maintenance expense increased for the nine-month period ended September 30, 2005, as compared to the same period in 2004, mainly due to higher plant operation costs at MEHC's Illinois plants resulting from higher planned maintenance. The increase was partially offset by a decrease in plant operating lease costs due to the termination of MEHC's Collins Station lease in April 2004.

### *Asset Impairment and Loss on Lease Termination*

Asset impairment and loss on lease termination for the nine-month period ended September 30, 2004 includes a \$954 million loss recorded during the second quarter of 2004 and a \$7 million loss recorded during the third quarter of 2004 related to the loss on the termination of MEHC's Collins Station lease, asset impairment, and related inventory reserves. MEHC concluded that the Collins Station was not economically competitive in the marketplace given generation overcapacity and ceased operations effective September 30, 2004. In addition, a \$29 million loss was recorded during the third quarter of 2004 related to the impairment of six of MEHC's small peaking units in Illinois.

### *Depreciation, Decommissioning and Amortization*

In millions	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
SCE	\$ 234	\$ 188	\$ 688	\$ 628
MEHC	30	39	91	112
Other	6	5	17	15
Edison International Consolidated	\$ 270	\$ 232	\$ 796	\$ 755

SCE's depreciation, decommissioning and amortization increased for the three- and nine-month periods ended September 30, 2005, as compared to the same periods in 2004, mainly due to a decrease in depreciation expense recorded in the third quarter of 2004 as a result of the implementation of the 2003 GRC related to the Palo Verde incremental cost incentive pricing rate-making mechanism, as well as depreciation expense associated with additions to transmission and distribution assets.

### *Other Income and Deductions*

#### *Interest and Dividend Income*

In millions	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
SCE	\$ 13	\$ 3	\$ 29	\$ 9
MEHC	15	(5)	43	—
Other	3	5	6	17
Edison International Consolidated	\$ 31	\$ 3	\$ 78	\$ 26

SCE's interest and dividend income increased for the three- and nine-month periods ended September 30, 2005, as compared to the same period in 2004, mainly due to interest income related to balancing account undercollections, as well as \$4 million related to interest on demand-side management and energy efficiency performance incentive claims resulting from a CPUC-approved settlement. See "SCE: Regulatory Matters—Other Regulatory Matters—Demand-Side Management and Energy Efficiency Performance Incentive Mechanisms" for further discussion. MEHC's interest and dividend income increased for both the three- and nine-month periods ended September 30, 2005, as compared to the same periods in 2004, primarily due to higher interest income resulting from higher average cash balances during the first nine months of 2005, compared to the corresponding period of 2004.

#### *Equity in Income from Partnerships and Unconsolidated Subsidiaries – Net*

Equity in income from partnerships and unconsolidated subsidiaries – net increased \$75 million for the nine-month period ended September 30, 2005, as compared to the same period in 2004. The increase is mainly due to increased earnings of approximately \$85 million from Edison Capital's global infrastructure funds, partially offset by the effects of accounting for variable interest entities consolidated upon adoption of a new accounting pronouncement in second quarter 2004, resulting in a decrease of approximately \$25 million. As a result, SCE now consolidates projects previously treated under the equity method by EME.

Third quarter equity in income from partnerships and unconsolidated subsidiaries – net from EME's energy projects is materially higher than equity in income from partnerships and unconsolidated subsidiaries – net related to other quarters of the year due to warmer weather during the summer months

and because a number of EME's energy projects located on the west coast have power sales contracts that provide for higher payments during the summer months.

*Other Nonoperating Income*

In millions	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
SCE	\$ 33	\$ 2	\$ 68	\$ 42
MEHC	1	6	2	54
Edison International Consolidated	\$ 34	\$ 8	\$ 70	\$ 96

SCE's other nonoperating income for the three- and nine-month periods ended September 30, 2005 includes a \$14 million incentive related to demand-side management and energy efficiency performance for the portion of the incentives previously collected in rates but which were deferred. See "SCE: Regulatory Matters—Other Regulatory Matters—Demand-Side Management and Energy Efficiency Performance Incentive Mechanisms" for further discussion of this matter. In addition, the quarter and year-to-date amounts include approximately \$10 million and \$20 million for the three- and nine-months ended September 30, 2005, respectively, related to an allowance for funds used during construction (AFUDC), which represents the estimated cost of equity funds that finance utility-plant construction, compared to approximately \$5 million and \$15 million in the same periods in 2004. The nine-month period ended September 30, 2005, also includes a \$7 million shareholder incentive related to the Mirant settlement received in the second quarter of 2005 (see "SCE: Regulatory Matters—Transmission and Distribution—Wholesale Electricity and Natural Gas Markets"), as well as a \$10 million reward for the efficient operation of Palo Verde during 2003, which was approved by the CPUC in 2005. SCE's other nonoperating income for the nine-month period ended September 30, 2004, includes \$19 million in rewards for the efficient operation of Palo Verde during 2001 and 2002, which were approved by the CPUC in 2004.

MEHC's other nonoperating income in 2004 consisted of a pre-tax gain of \$47 million on the sale of EME's interest in Four Star Oil & Gas on January 7, 2004 and a \$4 million loss related to the sale of MEHC's interest in Brooklyn Navy Yard Cogeneration Partners.

*Interest Expense – Net of Amounts Capitalized*

In millions	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
SCE	\$ 91	\$ 98	\$ 289	\$ 302
MEHC	101	120	305	334
Other	6	33	21	105
Edison International Consolidated	\$ 198	\$ 251	\$ 615	\$ 741

MEHC's interest expense – net of amounts capitalized decreased for the three- and nine-month periods ended September 30, 2005, as compared to the same periods in 2004, mainly due to the repayment of MEHC (parent)'s \$385 million term loan (\$100 million of the term loan was repaid in July 2004 and the remaining \$285 million of the term loan was repaid in January 2005). The year-to-date decrease was partially offset by higher interest expense at EME's Illinois plants, primarily attributable to higher interest rates on fixed rate debt issued in April 2004.

The decrease in interest expense – net of amounts capitalized related to Other for the three- and nine-month periods ended September 30, 2005, as compared to the same periods in 2004, was mainly due to the elimination of Edison International (parent)’s debt. Edison International (parent) has had no debt outstanding since the fourth quarter of 2004.

#### *Impairment Loss on Equity Method Investment*

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

#### *Loss on Early Extinguishment of Debt*

The loss on early extinguishment of debt in the nine-month period ended September 30, 2005, consisted of a \$20 million loss related to the early repayment of MEHC (parent)’s \$385 million term loan and a \$4 million loss related to the early repayment of EME’s junior subordinated debentures recorded during the first quarter of 2005.

#### *Other Nonoperating Deductions*

Other nonoperating deductions increased \$27 million and \$22 million for the three- and nine-month periods ended September 30, 2005, as compared to the same periods in 2004, mainly due to an accrual of \$26 million in system reliability penalties. See “SCE: Regulatory Matters—Other Regulatory Matters—System Reliability Incentive Mechanism” for further discussion of this matter.

#### *Income Tax (Benefit)*

In millions	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
SCE	\$ 52	\$ 174	\$ 176	\$ 398
MEHC	95	22	89	(389)
Other	(18)	(15)	2	(49)
Edison International Consolidated	\$ 129	\$ 181	\$ 267	\$ (40)

Edison International’s effective tax rates were 23% and 25% for the three- and nine-month periods ended September 30, 2005, respectively, as compared to 37% and 55% for the same periods in 2004. The decreased effective tax rates resulted primarily from recording a \$65 million benefit, including \$57 million of interest income, in the third quarter of 2005 related to a settlement reached with the IRS on tax issues and pending affirmative claims relating to Edison International’s 1991–1993 tax years. See “Other Developments—Federal Income Taxes” for further discussion of this matter. Additional decreases to the effective rates resulted from reductions made to accrued tax liabilities in 2005 to reflect progress made in settlement negotiations related to tax audits other than the 1991–1993 tax years, changes in

property-related flow-through items at SCE and adjustments made to tax balances in 2005 at MEHC and SCE.

### ***Minority Interest***

Minority interest represents the effects of the adoption of a new accounting pronouncement in second quarter 2004 related to SCE's variable interest entities.

### ***Income from Discontinued Operations***

The third-quarter 2005 earnings from discontinued operations primarily reflect positive tax adjustment of \$28 million resulting from the sales of MEHC's international projects. Beginning in the third quarter of 2004, MEHC reclassified the results of its international projects to discontinued operations for all periods presented due to completion of the sale of its interest in Contact Energy and its agreement to sell the remaining international projects. Earnings from discontinued operations during the third quarter of 2004, including a gain and recognition of a tax benefit, were \$499 million. Earnings from discontinued operations for the nine months ended September 30, 2005 were \$55 million including positive tax adjustments of \$28 million related to MEHC's international asset sales and distributions from MEHC's Lakeland project of \$24 million. Earnings from discontinued operations for the nine months ended September 30, 2004 were \$570 million representing the operating results, gain on sale and recognition of tax benefits related to MEHC's international projects.

### ***Cumulative Effect of Accounting Change – Net of Tax***

Edison International's results for the nine-month period ended September 30, 2004, include a charge for the cumulative effect of a change in accounting principle reflecting the impact of Edison Capital's implementation of an accounting standard that requires the consolidation of certain variable interest entities.

### ***Historical Cash Flow Analysis***

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

### ***Cash Flows from Operating Activities***

Net cash provided by operating activities:

<u>In millions</u>	<u>Nine-Month Period Ended September 30,</u>	<u>2005</u>	<u>2004</u>
Continuing operations		<b>\$1,680</b>	\$ 629

The 2005 change in cash provided by operating activities from continuing operations was mainly due an increase in short-term regulatory balancing account collections, partially offset by required margin and collateral deposits in 2005 mainly for MEHC's price risk management and trading activities resulting from an increase in forward market prices. In addition, the change in cash provided by operating activities results from the timing of cash receipts and disbursements related to working capital items.

## *Cash Flows from Financing Activities*

Net cash provided (used) by financing activities:

In millions	Nine-Month Period Ended September 30,	2005	2004
Continuing operations		\$ (955)	\$ 228

Cash provided (used) by financing activities from continuing operations mainly consisted of long-term and short-term debt payments at SCE and EME.

Financing activities in the nine-month period ended September 30, 2005, were mainly related to SCE. SCE's first quarter 2005 financing activity included the issuance of \$650 million of first and refunding mortgage bonds. The issuance included \$400 million of 5% bonds due in 2016 and \$250 million of 5.55% bonds due in 2036. The proceeds were used to redeem the remaining \$50,000 of its 8% first and refunding mortgage bonds due February 2007 (Series 2003A) and \$650 million of the \$966 million 8% first and refunding mortgage bonds due February 2007 (Series 2003B). SCE's second quarter financing activity included the issuance of \$350 million of its 5.35% first and refunding mortgage bond due in 2035 (Series 2005E). A portion of the proceeds was used to redeem \$316 million of its 8% first and refunding mortgage bonds due in 2007 (Series 2003B). In addition, in April 2005, SCE issued 4,000,000 shares of Series A preference stock (non-cumulative, \$100 liquidation value) and received net proceeds of approximately \$394 million. Approximately \$81 million of the proceeds was used to redeem all the outstanding shares of its \$100 cumulative preferred stock, 7.23% Series, and approximately \$64 million of the proceeds was used to redeem all the outstanding shares of its \$100 cumulative preferred stock, 6.05% Series. SCE's third quarter 2005 financing activity included the issuance of 2,000,000 shares of Series B preference stock (non-cumulative, \$100 liquidation value) and received net proceeds of approximately \$197 million. MEHC's first quarter financing activity included the repayment of the remaining \$285 million of the term loan, \$11 million paid for the call premium on the retirement of the term loan and the repayment of the junior subordinated debentures of \$150 million. MEHC's second quarter activity included a \$302 million repayment in April 2005 related to Midwest Generation's existing term loan. Financing activities in 2005 also include dividend payments of \$244 million paid by Edison International to its shareholders.

Financing activities in the nine-month period ended September 30, 2004 included repurchases of approximately \$47 million of Edison International (parent)'s \$618 million 6-7/8% notes due September 2004 and paid the remaining balance in September 2004. SCE financing activities include the issuance of \$300 million of 5% bonds due in 2014, \$525 million of 6% bonds due in 2034 and \$150 million of floating rate bonds due in 2006 during the first quarter of 2004. The proceeds from these issuances were used to redeem \$300 million of 7.25% first and refunding mortgage bonds due March 2026, \$225 million of 7.125% first and refunding mortgage bonds due July 2025, \$200 million of 6.9% first and refunding mortgage bonds due October 2018, and \$100 million of junior subordinated deferrable interest debentures due June 2044. In addition, during the first quarter of 2004, SCE paid the \$200 million outstanding balance of its credit facility, as well as remarketed approximately \$550 million of pollution-control bonds with varying maturity dates ranging from 2008 to 2040. Approximately \$354 million of these pollution-control bonds had been held by SCE since 2001 and the remaining \$196 million were purchased and reoffered in 2004. In March 2004, SCE issued \$300 million of 4.65% first and refunding mortgage bonds due in 2015 and \$350 million of 5.75% first and refunding mortgage bonds due in 2035. A portion of the proceeds from the March 2004 first and refunding mortgage bond issuances were used to fund the acquisition and construction of the Mountainview project. During the third quarter, SCE paid \$125 million of 5.875% bonds due in September 2004. EME's financing activities included the \$1 billion secured notes and \$700 million term loan facility received by Midwest Generation in April 2004, the repayment of \$693 million related to Edison Mission Midwest Holdings' credit facility, \$28 million related to the EME's Coal and Capex facility in April 2004, and \$100 million related to MEHC's \$385

million term loan in July 2004. Financing activities in 2004 also included dividend payments of \$195 million paid by Edison International to its shareholders.

### ***Cash Flows from Investing Activities***

Net cash used by investing activities:

In millions	Nine-Month Period Ended September 30,	2005	2004
Continuing operations		\$ (891)	\$ (562)

Cash flows from investing activities are affected by capital expenditures, EME's sales of assets and SCE's funding of nuclear decommissioning trusts.

Investing activities for the nine-month period ended September 30, 2005 reflect \$1.3 billion in capital expenditures at SCE, primarily for transmission and distribution assets, including approximately \$43 million for nuclear fuel acquisitions, and \$41 million in capital expenditures at EME. Investing activities also include \$140 million in net sales of auction rate securities at EME and \$124 million in proceeds received in 2005 from the sale of EME's 25% investment in the Tri Energy project and EME's 50% investment in the CBK project, as well as a decrease in restricted cash and customer advances for construction.

Investing activities for the nine-month period ended September 30, 2004 reflect \$1.1 billion in capital expenditures at SCE, primarily for transmission and distribution assets, including approximately \$59 million for nuclear fuel acquisitions, and \$39 million in capital expenditures at EME. In addition, investing activities include \$285 million of acquisition costs related to the Mountainview project at SCE, and \$118 million in proceeds received from the sale of 100% of EME's stock of Edison Mission Energy Oil & Gas and the sale of EME's interest in the Brooklyn Navy Yard project, and \$739 million in proceeds received in 2004 at EME from the sale of its interest in Contact Energy. Cash flows from investing activities also reflect a decrease in restricted cash.

### **DISCONTINUED OPERATIONS**

On February 3, 2005, EME sold its 25% equity interest in the Tri Energy project, pursuant to a purchase agreement dated December 15, 2004, to a consortium comprised of International Power plc (70%) and Mitsui & Co., Ltd. (30%), referred to as IPM, for approximately \$20 million. The sale of this investment had no significant effect on net income in the first quarter of 2005.

On January 10, 2005, EME sold its 50% equity interest in the Caliraya-Botocan-Kalayaan project to Corporacion IMPSA S.A., pursuant to a purchase agreement dated November 5, 2004. Proceeds from the sale were approximately \$104 million. EME recorded a pre-tax gain on the sale of approximately \$9 million during the first quarter of 2005.

EME previously owned and operated a 220 MW combined cycle, natural gas-fired power plant located in the United Kingdom, known as the Lakeland project. The ownership of the project was held through EME's indirect subsidiary, Lakeland Power Ltd., which sold power generated from the plant pursuant to a power sales agreement with Norweb Energi Ltd., a subsidiary of TXU (UK) Holdings Limited (TXU UK) and an indirect subsidiary of TXU Europe Group plc (TXU Europe). EME ceased consolidating the activities of Lakeland Power Ltd. in 2002, when an administrative receiver was appointed following a default by Norweb Energi Ltd. under the power sales agreement. Accordingly, EME accounts for its ownership of Lakeland Power Ltd. on the cost method and earnings are recognized as cash is distributed from this entity.

As previously disclosed, the administrative receiver of Lakeland Power Ltd. filed a claim against Norweb Energi Ltd. for termination of the power sales agreement. On November 19, 2002, TXU UK and TXU Europe, together with a related entity, TXU Europe Energy Trading Limited, entered into formal administration proceedings of their own in the United Kingdom (similar to bankruptcy proceedings in the United States). On March 31, 2005, Lakeland Power Ltd. received £112 million (approximately \$210 million) from the TXU administrators, representing an interim payment of 97% of its accepted claim of £116 million (approximately \$217 million).

From the amount received, Lakeland Power Ltd., now controlled by a liquidator in the United Kingdom, has made a payment of £20 million (approximately \$37 million) to EME on April 7, 2005 comprised of £7 million (approximately \$13 million) for a secured loan which EME purchased from Lakeland Power Ltd.'s secured creditors in 2004 and certain unsecured receivables from Lakeland Power Ltd., and £13 million (approximately \$24 million) as a distribution to the EME subsidiary that owns the equity interest in Lakeland Power Ltd. This distribution was recognized in income during the quarter ended June 30, 2005. Additionally, Lakeland Power Ltd. will pay to EME's subsidiary that owns the equity interest in Lakeland Power Ltd. the amount remaining after resolution of any remaining secured and unsecured creditor claims and payment of or provision for tax liabilities and the fees and expenses associated with Lakeland Power Ltd.'s liquidation.

EME estimates that the remaining net proceeds after tax (including taxes due in the United States) and net income resulting from the above payments will be approximately \$64 million. The majority of the remaining proceeds are expected to be received in 2006, when Lakeland Power Ltd.'s liquidation is expected to be completed. Because the amounts required to settle outstanding claims and UK taxes have not been finalized and cannot be estimated precisely in the context of the liquidation, the actual amount of net proceeds and increase in net income may vary materially from the above estimate.

For all periods presented, the results of EME's international projects, except for the Doga project (discussed in MEHC: Other Developments—Agreement to Sell the Doga Project"), have been accounted for as discontinued operations in the consolidated financial statements in accordance with an accounting standard related to the impairment and disposal of long-lived assets.

There was no revenue from discontinued operations in 2005. For the three and nine months ended September 30, 2004, revenue from discontinued operations was \$354 million and \$1.1 billion, respectively. For the three months ended September 30, 2005 and 2004, pre-tax income (loss) was \$(2) million and \$41 million, respectively. For the nine months ended September 30, 2005 and 2004, pre-tax income was \$20 million and \$165 million, respectively.

During the third quarter ended September 30, 2005, EME recorded tax adjustments of \$28 million which resulted from the completion of the 2004 federal and California income tax returns and quarterly review of tax accruals. The majority of the tax adjustments are related to the sale of the international assets. These adjustments (benefits) are included in income from discontinued operations – net of tax on the consolidated income statement. During the quarter ended September 30, 2004, EME recorded a deferred income tax benefit of \$327 million to recognize the higher tax basis of its international holding company over its book basis as required by accounting rules applicable to discontinued operations.

## **NEW AND PROPOSED ACCOUNTING PRINCIPLES**

In March 2005, the FASB issued an interpretation related to accounting for conditional asset retirement obligations (AROs). This Interpretation clarifies that an entity is required to recognize a liability for the fair value of a conditional ARO if the fair value can be reasonably estimated even though uncertainty exists about the timing and/or method of settlement. This Interpretation is effective December 31, 2005. Thus far, Edison International has identified conditional AROs related to: treated wood poles, hazardous materials such as mercury and polychlorinated biphenyls-containing equipment; and asbestos removal

costs at buildings, operating stations and retired units. Additional assessment is necessary to value these AROs. However, since SCE follows accounting principles for rate-regulated enterprises and receives recovery of these costs through rates, implementation of this interpretation at SCE will not affect Edison International's earnings. Implementation of this interpretation at EME is expected to have a minimal impact on Edison International's earnings.

A new accounting standard requires companies to use the fair value accounting method for stock-based compensation. Edison International currently uses the intrinsic value accounting method for stock-based compensation. On April 14, 2005, the Securities and Exchange Commission announced a delay in the effective date for the new standard to fiscal years beginning after June 15, 2005. Edison International will implement the new standard effective January 1, 2006 by applying the modified prospective transition method. The difference in expense between the two accounting methods related to stock options granted is an increase of \$2 million and \$7 million in expense for the three- and nine-month periods ended September 30, 2005, respectively. Edison International is assessing the impact of this accounting standard on its performance shares.

The American Jobs Creation Act of 2004 included a tax deduction on qualified production activities income (including income from the sale of electricity). In December 2004, the FASB issued guidance that this deduction should be accounted for as a special deduction, rather than a tax rate reduction. Accordingly, the special deduction is recorded in the year it is earned. In October 2005, the IRS issued proposed regulations for this tax deduction. The tax deduction is not expected to materially affect Edison International's 2005 financial statements. Edison International is evaluating the effect that the manufacturer's deduction will have in subsequent years.

In March 2004, the FASB issued new accounting guidance for the effect of participating securities on EPS calculations and the use of the two-class method. The new guidance, which was effective in second quarter 2004, requires the use of the two-class method of computing EPS for companies with participating securities (including vested stock options with dividend equivalents).

Basic EPS is computed by dividing net income available for common stock by the weighted-average number of common shares outstanding. Net income (loss) available for common stock was \$459 million and \$813 million for the three months ended September 30, 2005, and 2004, respectively, and was \$859 million and \$537 million for the nine months ended September 30, 2005, and 2004, respectively. In arriving at net income, dividends on preferred securities and preferred stock have been deducted.

In December 2003, the FASB issued a revision to an accounting Interpretation (originally issued in January 2003), Consolidation of Variable Interest Entities (VIEs). The primary objective of the Interpretation is to provide guidance on the identification of, and financial reporting for, VIEs, where control may be achieved through means other than voting rights. Under the Interpretation, the enterprise that is expected to absorb or receive the majority of a VIE's expected losses or residual returns, or both, must consolidate the VIE, unless specific exceptions apply. This Interpretation was effective for special purpose entities, as defined by accounting principles generally accepted in the United States, as of December 31, 2003, and all other entities as of March 31, 2004. Edison International implemented the Interpretation for its special purpose entities as of December 31, 2003.

On March 31, 2004, SCE consolidated four power projects partially owned by EME, EME deconsolidated two power projects, and Edison Capital consolidated two affordable housing partnerships and three wind projects. Edison International recorded a cumulative effect adjustment that decreased net income by less than \$1 million, net of tax, due to negative equity at one of Edison Capital's newly consolidated entities.

On July 14, 2005, the FASB issued an exposure draft on accounting for uncertain tax positions. An enterprise would recognize, in its financial statements, the benefit of a tax position only if that position is

probable of being sustained on audit based solely on the technical merits of the position. The comment period for the exposure draft ended on September 12, 2005; the earliest the guidance would be implemented would be December 31, 2005. Edison International is evaluating the potential impact of the proposal on its financial statements.

## **COMMITMENTS, GUARANTEES AND INDEMNITIES**

The following is an update to Edison International's commitments, guarantees and indemnities. See the "Commitments, Guarantees and Indemnities" section of the year-ended 2004 MD&A for a detailed discussion.

### **Fuel Supply Contracts**

Midwest Generation and EME Homer City have entered into additional fuel purchase commitments with various third-party suppliers during the first nine months of 2005. These additional commitments are currently estimated to be \$22 million for 2005, \$114 million for 2006, \$169 million for 2007, \$44 million for 2008, and \$62 million for 2009.

Beginning in 2004, EME Homer City experienced interruptions of supply under two agreements with Unionvale Coal Company and Genesis, Inc. Unionvale and Genesis claimed that alleged geologic conditions at the Genesis No. 17 Mine in Pennsylvania, which is one source of coal under these multi-source coal contracts, constituted force majeure and excused contract performance. These two agreements together provide for the delivery to EME Homer City of approximately 20% of EME Homer City's clean coal requirements in 2005 and 2006, and approximately 10% in 2007. Claims arising from these matters have been resolved in a confidential settlement and the lawsuit has been dismissed. EME Homer City has awarded contracts to alternate suppliers, and adjusted its inventory strategies to reflect and offset the delivery shortfall for 2005.

During the second quarter of 2005, SCE amended one of its coal fuel contracts which reduced the term of the contract. As a result of this modification, the fuel supply contract payments for the thereafter period decreased by \$158 million.

### **Gas and Coal Transportation**

Midwest Generation has contractual agreements for the transport of coal to its facilities. The primary contract is with Union Pacific Railroad (and various delivering carriers) which extend through 2011. Midwest Generation commitments under this agreement are based on actual coal purchases from the Powder River Basin. Accordingly, contractual obligations for transportation are based on coal volumes set forth in fuel supply contracts. The increase in transportation commitments entered into during the first nine months of 2005 relates to additional volumes of fuel purchases using the terms of existing transportation agreements. These commitments are currently estimated to be \$33 million for 2005, \$61 million for 2006, \$117 million for 2007, \$40 million for 2008, and \$77 million for 2009.

### **Power-Purchase Contracts**

During the first quarter of 2005, SCE entered into additional power call option contracts. SCE's revised purchased-power capacity payment commitments under these contracts are currently estimated to be \$31 million for 2005, \$95 million for 2006, \$101 million for 2007 and \$84 million for 2008.

### **Leases**

During the first quarter of 2005, SCE entered into new power contracts in which SCE takes virtually all of the power. In accordance with an accounting standard, these power contracts are classified as operating

leases. SCE's commitments under these operating leases are currently estimated to be \$39 million for 2005, \$55 million for 2006, \$50 million for 2007 and \$43 million for 2008.

## **OTHER DEVELOPMENTS**

### **Environmental Matters**

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.

### ***Environmental Remediation***

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.

Edison International's recorded estimated minimum liability to remediate its 29 identified sites at SCE (22 sites) and EME (7 sites related to Midwest Generation) is \$84 million, \$81 million of which is related to SCE. 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 \$115 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 33 immaterial sites whose total liability ranges from \$4 million (the recorded minimum liability) to \$10 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing \$29 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of \$55 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.

Edison International 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 \$25 million. Recorded costs for the twelve months ended September 30, 2005 were \$11 million.

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 Income Taxes**

Edison International has reached a settlement with the IRS on tax issues and pending affirmative claims relating to its 1991–1993 tax years. This settlement, which was signed by Edison International in March 2005 and approved by the United States Congress Joint Committee on Taxation on July 27, 2005, resulted in a third quarter 2005 net earnings benefit for Edison International of approximately \$65 million, including interest, most of which relates to SCE. This benefit was reflected in the income statement caption "Income tax (benefit)."

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994–1996 and 1997–1999 tax years, respectively. Many of the asserted tax deficiencies are timing differences and, therefore, amounts ultimately paid (exclusive of interest and penalties), if any, would be deductible on future tax returns of Edison International.

As part of a nationwide challenge of certain types of lease transactions, the IRS has raised issues about the deferral of income taxes in audits of the 1994–1996 and 1997–1999 tax years associated with Edison Capital's cross-border leases. The IRS is challenging Edison Capital's foreign power plant and electric locomotive sale/leaseback transactions (termed a sale-in/lease-out or SILO transaction). The estimated federal and state taxes deferred from these leases were \$44 million in the 1994–1996 and 1997–1999 audit periods and \$32 million in subsequent years through 2004.

The IRS is also challenging Edison Capital's foreign power plant and electric transmission system lease/leaseback transactions (termed a lease-in, lease-out or LILO transaction). The estimated federal and state income taxes deferred from these leases were \$558 million in the 1997–1999 audit period and \$565 million in subsequent years through 2004. The IRS has also proposed interest and penalties in its challenge to each SILO and LILO transaction.

Edison International believes it properly reported these transactions based on applicable statutes, regulations and case law in effect at the time the transactions were entered into. Written protests were filed to appeal the 1994–1996 audit adjustments asserting that the IRS's position misstates material facts, misapplies the law and is incorrect. This matter is now being considered by the Administrative Appeals branch of the IRS. Edison International also filed protests in March 2005 to appeal the issues raised in the 1997–1999 audit.

Edison Capital also entered into a lease/service contract transaction in 1999 involving a foreign telecommunication system (termed a Service Contract). The IRS did not assert an adjustment for this

lease in the 1997–1999 audit cycle but is expected to challenge this lease in subsequent audit cycles similar to positions asserted against the SILOs discussed above. The estimated federal and state taxes deferred from this lease are \$221 million through 2004.

If Edison International is not successful in its defense of the tax treatment for the SILOs, LILOs and the Service Contract, the payment of taxes, exclusive of any interest or penalties, would not affect results of operations under current accounting standards, although it could have a significant impact on cash flow. However, the FASB is currently considering changes to the accounting for leases. If the proposed accounting changes are adopted and Edison International's tax treatment for the SILOs, LILOs and Service Contract is significantly altered as a result of IRS challenges, there could be a material effect on reported earnings by requiring Edison International to reverse earnings previously recognized as a current period adjustment and to report these earnings over the remaining life of the leases. At this time, Edison International is unable to predict the impact of the ultimate resolution of these matters.

The IRS Revenue Agent Report for the 1997–1999 audit also asserted deficiencies with respect to a transaction entered into by an SCE subsidiary which may be considered substantially similar to a listed transaction described by the IRS as a contingent liability company. While Edison International intends to defend its tax return position with respect to this transaction, the tax benefits relating to the capital loss deductions will not be claimed for financial accounting and reporting purposes until and unless these tax losses are sustained.

In April 2004, Edison International filed California Franchise Tax amended returns for tax years 1997 through 2002 to abate the possible imposition of new California penalty provisions on transactions that may be considered as listed or substantially similar to listed transactions described in an IRS notice that was published in 2001. These transactions include certain Edison Capital leveraged lease transactions and the SCE subsidiary contingent liability company transaction described above. Edison International filed these amended returns under protest retaining its appeal rights.

## **EDISON INTERNATIONAL**

### **Item 3. Quantitative and Qualitative Disclosures About Market Risk**

Information responding to Part I, Item 3 is included in Part I, Item 2, “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” under the headings “SCE: Market Risk Exposures,” “MEHC: Market Risk Exposures,” “Edison Capital: Market Risk Exposures,” and “Edison International (Parent): Market Risk Exposures” and is incorporated herein by this reference.

### **Item 4. Controls and Procedures**

#### *Disclosure Controls and Procedures*

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

#### *Internal Control Over Financial Reporting*

There were no changes in Edison International’s internal control over financial reporting (as that term is defined in Rules 13a-15(f) or 15d-15(f) under the Exchange Act) during the quarter to which this report relates that have materially affected, or are reasonably likely to materially affect, Edison International’s internal control over financial reporting.

## **PART II – OTHER INFORMATION**

### **Item 1. Legal Proceedings**

Edison International or its subsidiaries are party to certain lawsuits and legal proceedings, which are described in Part I, Item 3 of Edison International's Annual Report on Form 10-K for the year ended December 31, 2004. The following is a description of material developments during the period covered by this Quarterly Report and should be read in conjunction with the Annual Report referenced above. There were no significant developments with respect to litigation required to be disclosed under Part II, Item I of Form 10-Q of Edison International or its subsidiaries during the quarterly period ended September 30, 2005, except as follows:

#### **Southern California Edison Company**

##### *Navajo Nation Litigation*

See Note 4, "Contingencies – Navajo Nation Litigation" of Notes to Consolidated Financial Statements for minor updates on litigation involving SCE and the Navajo Nation which was previously reported in Part I, Item 3 of Edison International's Annual Report on Form 10-K for the year ended December 31, 2004, and in Part II, Item 1 of Edison International's Quarterly Report on Form 10-Q for the period ended March 31, 2005, and Edison International's Quarterly Report on Form 10-Q for the period ended June 30, 2005.

##### *Department of the Army, Los Angeles District, Corps of Engineers/Notice of Violation of Clean Water Act*

In December 2004, the US Army Corps of Engineers (Corps) sent SCE a Notice of Violation (Notice), alleging that SCE or its contractors had discharged fill material into wetlands adjacent to the Santa Ana River (River), in the City of Huntington Beach, CA (City). Under Sections 301 and 404 of the Clean Water Act, the discharge of fill material into waters of the United States is unlawful unless first permitted by the Corps pursuant to Section 404 of the Clean Water Act.

The Notice provided a general description of the area in question but did not specify the location of the violation. Following discussions and correspondence with the Corps, it was determined that the Corps was concerned about the actions of a certain licensee of SCE on an SCE-owned transmission right-of-way corridor located adjacent to the River. SCE's licensee, or its predecessor-in-interest, had obtained from the City a Conditional Use Permit (CUP) to locate landscape nursery operations within the right-of-way corridor. The CUP required the licensee to perform certain drainage and grading improvements to the property before locating nursery operations on site. During the course of the grading work, the licensee brought additional soil onto SCE's property for use as fill material.

Pursuant to the Notice, potential penalties for violation of Section 404 of the Clean Water Act include a maximum criminal fine of \$50,000 per day and imprisonment for up to three years, and a maximum civil penalty of \$25,000 per day of violation. To date, however, the Corps has not proposed to impose any specific fine or penalty on SCE with respect to the subject matter of the Notice.

In the process of investigating the matter, the Corps has requested that SCE perform a wetlands delineation study of the property to determine whether the property in question qualifies as a wetland area subject to Corps jurisdiction. SCE has hired a consulting group to perform the wetlands delineation study.

## **Mission Energy Holding Company**

### *Sunrise Power Company*

Sunrise Power Company, in which EME's wholly owned subsidiary owns a 50% interest, sells all its output to the California Department of Water Resources. On May 15, 2002, Sunrise Power Company was served with a complaint filed in the Superior Court of the State of California, City and County of San Francisco, by James M. Millar, "individually, and on behalf of the general public and as a representative taxpayer suit" against sellers of long-term power to the California Department of Water Resources, including Sunrise Power Company. The lawsuit alleges that the defendants, including Sunrise Power Company, engaged in unfair and fraudulent business practices by knowingly taking advantage of a manipulated power market to obtain unfair contract terms. The lawsuit seeks to enjoin enforcement of the "unfair and oppressive terms and conditions" in the contracts, as well as restitution by the defendants of excessive monies obtained by the defendants. Plaintiffs in several other class action lawsuits pending in Northern California have filed petitions seeking to have the Millar lawsuit consolidated with those lawsuits. In December 2003, James Millar filed a First Amended Class Action and Representative Action Complaint which contains allegations similar to those in the earlier complaint but also alleges a class action. One of the newly added parties removed the lawsuit to federal court, and the court ordered remand to the San Francisco Superior Court. Defendants filed a responding pleading on May 6, 2005. Following a hearing on September 7, 2005, the court sustained defendants' demurrer regarding preemption and filed rate doctrine. The plaintiff has waived his right to appeal.

## Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

### (c) Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table contains information about all purchases made by or on behalf of Edison International or any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Exchange Act) of shares or other units of any class of Edison International's equity securities that is registered pursuant to Section 12 of the Exchange Act.

Period	(a) Total Number of Shares (or Units) Purchased <sup>1</sup>	(b) Average Price Paid per Share (or Unit) <sup>1</sup>	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
July 1, 2005 to July 31, 2005	1,200,269	\$40.28	—	—
August 1 to August 31, 2005	1,796,658	\$41.21	—	—
September 1, 2005 to September 30, 2005	1,579,506	\$46.19	—	—
Total	4,576,433	\$42.68	—	—

<sup>1</sup> The shares were purchased by agents acting on Edison International's behalf for delivery to plan participants to fulfill requirements in connection with Edison International's (i) 401(k) Savings Plan, (ii) Dividend Reinvestment and Direct Stock Purchase Plan, and (iii) long-term incentive compensation plans. The shares were purchased in open-market transactions pursuant to plan terms or participant elections. Edison International did not control the quantity of shares purchased, the timing of the purchases or the price of the shares purchased in these transactions. The shares were never registered in Edison International's name and none of the shares purchased were retired as a result of the transactions.

## Item 6. Exhibits

### Edison International

- 3 Bylaws of Edison International, as Amended to and including October 20, 2005 (File No. 1-9936, filed as Exhibit 3.1 to Edison International's Form 8-K dated October 24, 2005, and filed on October 26, 2005)\*
- 10.1 Retirement Agreement, dated as of August 25, 2005, between Southern California Edison Company and Robert Foster (File No. 1-02313, filed as Exhibit 10.1 to Southern California Edison Company's Form 8-K dated August 25, 2005 and filed on August 26, 2005)\*
- 10.2 Consulting Agreement, dated as of August 25, 2005, between Southern California Edison Company and Robert Foster (File No. 1-02313, filed as Exhibit 10.2 to Southern California Edison Company's Form 8-K dated August 25, 2005, and filed on August 26, 2005)\*
- 10.3 Engagement Letter for Legal Services between Edison International and Bryant C. Danner, effective September 28, 2005 (File No. 1-9936, filed as Exhibit 99.1 to Edison International's Form 8-K dated September 28, 2005, and filed on October 4, 2005)\*
- 10.4 Legal Fees Reimbursement, dated September 2005 (File No. 1-02313, filed as Exhibit 10.3 to Southern California Edison Company's Form 10-Q for the quarter ended September 30, 2005)\*
- 31.1 Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act
- 31.2 Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act
- 32 Statement Pursuant to 18 U.S.C. Section 1350

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\*Incorporated herein by reference pursuant to Rule 12b-32.

**SIGNATURE**

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EDISON INTERNATIONAL  
(Registrant)

By

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LINDA G. SULLIVAN  
Vice President and Controller  
(Duly Authorized Officer and  
Principal Accounting Officer)

Dated: November 4, 2005