EDISON INTERNATIONAL®

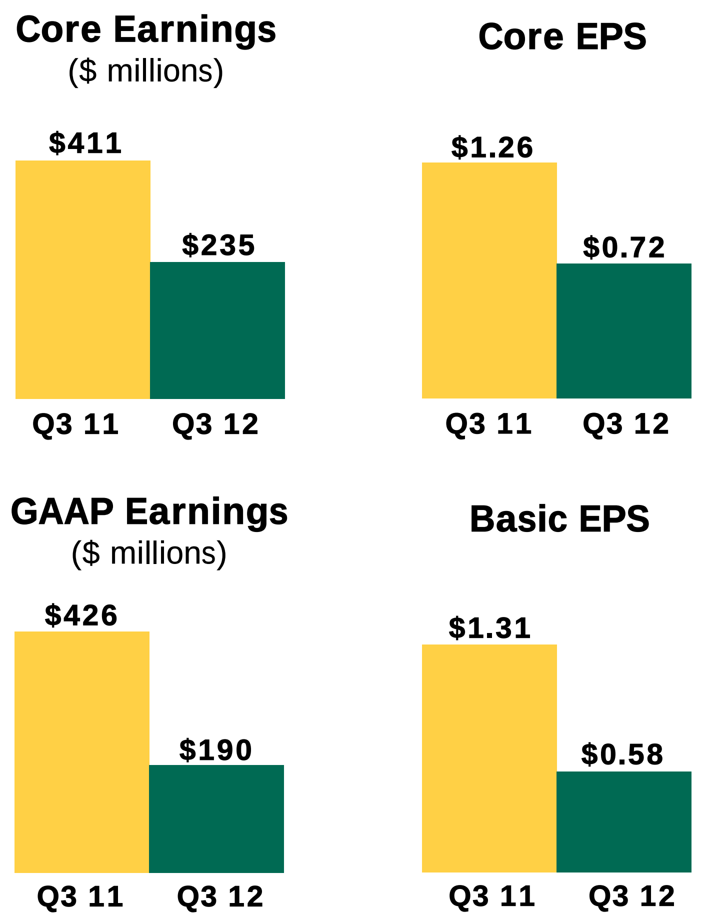
Third Quarter 2012 Financial Teleconference

Forward-Looking Statements

Statements contained in this presentation about future performance, including, without limitation, operating results, asset and rate base growth, capital expenditures, San Onofre Nuclear Generating Station (SONGS), EME liquidity and restructuring activities, and other statements that are not purely historical, are forward-looking statements. These forward-looking statements reflect our current expectations; however, such statements involve risks and uncertainties. Actual results could differ materially from current expectations. These forward-looking statements represent our expectations only as of the date of this presentation, and Edison International assumes no duty to update them to reflect new information, events or circumstances. Important factors that could cause different results are discussed under the headings “Risk Factors,” and “Management’s Discussion and Analysis” in Edison International’s 2011 Form 10-K, most recent Form 10-Q and other reports filed with the Securities and Exchange Commission, which are available on our website: www.edisoninvestor.com. These filings also provide additional information on historical and other factual data contained in this presentation.

Third Quarter Earnings Summary

	Q3 11	Q3 12	Variance
Core EPS[1]			
SCE	$1.25	$1.11	$(0.14)
EMG	0.05	(0.28)	(0.33)
EIX parent company and other[2]	(0.04)	(0.11)	(0.07)
Core EPS	**$1.26**	**$0.72**	**$(0.54)**
Non-Core Items			
SCE	$ —	$ —	$ —
EMG[3]	0.05	(0.14)	(0.19)
EIX parent company and other	—	—	—
Total Non-Core	$ 0.05	$(0.14)	$(0.19)
Basic EPS	**$1.31**	**$0.58**	**$(0.73)**
Diluted EPS	**$1.30**	**$0.58**	**$(0.72)**



1 See Earnings Non-GAAP Reconciliations And Use of Non-GAAP Financial Measures in Appendix. The impact of participating securities is included in EIX parent company and other, and was zero per share for the quarters ended September 30, 2012, and September 30, 2011.

2 EIX parent company and other for the quarter ended September 30, 2012, includes $(0.09) per share for state income tax adjustments related to prior and future periods.

3 Non-core items for the quarter ended September 30, 2012, include Homer City, Edison Capital asset sale, and other. Non-core items for the quarter ended September 30, 2011, include earnings for Homer City only.

SCE Third Quarter Highlights

EPS	Q3 11	Q3 12	Variance
Core[1]	$1.25	$1.11	$(0.14)
Non-Core Items	—	—	—
Basic EPS[1]	**$1.25**	**$1.11**	**$(0.14)**

Key Core Earnings Drivers	
2012 GRC delay items:	
Depreciation	$(0.05)
Net interest expense	(0.04)
SONGS	
Inspection and repair	(0.09)
Severance	(0.06)
O&M reductions and other	0.06
Income taxes and other	0.04
Total	$(0.14)

Recent Developments

- September 2012, SCE filed proposed formula rate update with 2013 transmission revenue requirement of $900 million, representing an increase of $178 million, or 25%, over 2012 revenue requirement
- October 2012:
  - 2012 GRC Proposed Decision released (see page 4)
  - CPUC approved SONGS OII to consider appropriate cost recovery – all SONGS costs since January 1 tracked in separate memo account (see page 7)
  - SCE submitted response to Confirmatory Action Letter and restart plans for Unit 2 to the NRC (see page 7)

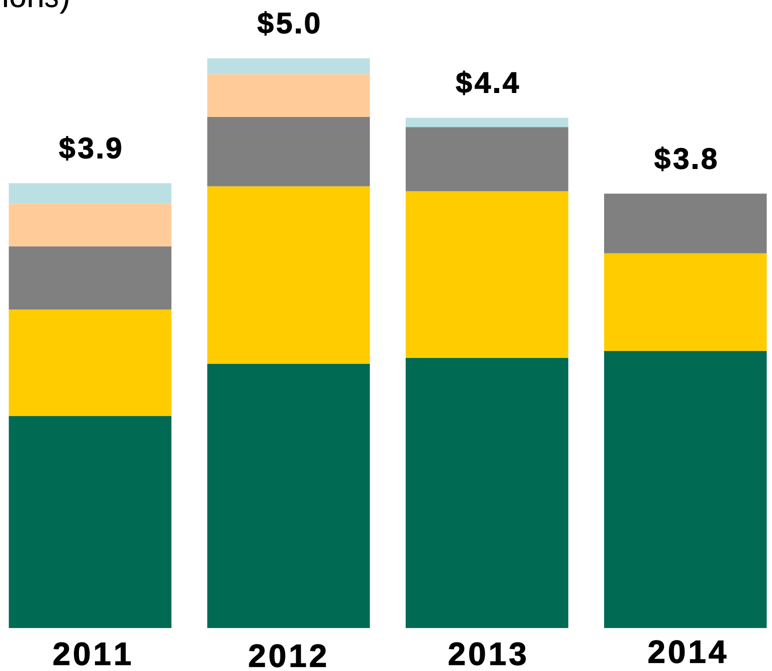
1 See Non-GAAP Reconciliations and Use of Non-GAAP Financial Measures in Appendix for reconciliation of core earnings per share to basic earnings per share.

SCE 2012 CPUC General Rate Case (A.10-11-015)

- Proposed Decision issued on October 19 with 2012 revenue requirement of $5,693 million
  - Decrease of $601 million from SCE's request primarily related to O&M with some plant-related capital reductions
  - $929 million capital expenditures removed (2010 – 2012)
  - Proposed CPUC rate base of $15,086 million in 2012
  - Proposed post-test year escalation on capital additions of 3.05% for 2013, and 2.93% for 2014
  - SONGS revenue requirement subject to refund and reasonableness review, and tracked in memorandum account pending outcome of outage investigation
- SCE believes PD is consistent with Range Cases provided in rate base forecast
- Final decision retroactive to January 1, 2012, through memorandum account, except for SONGS
  - SCE expects to adjust its total spending to amount authorized by Commission
  - SCE's ongoing goal is to earn its authorized returns as set by the CPUC and FERC

SCE Capital Expenditures Forecast

($ billions)



Forecast Range[1]	2011	2012	2013	2014	Total
Request		$5.0	$4.4	$3.8	$13.2
GRC PD[2]		$4.6	$4.2	$3.7	$12.5
Range		$4.4	$4.0	$3.4	$11.8

Forecast By Classification

	$	%
Solar Photovoltaic	0.2	1
Edison SmartConnect®	0.4	3
Generation	1.7	13
Transmission	3.8	29
Distribution	7.1	54
Total	13.2	100

By Proceeding

	%
2012 CPUC Rate Case	68
Other CPUC	3
FERC Cases	29
Total	100

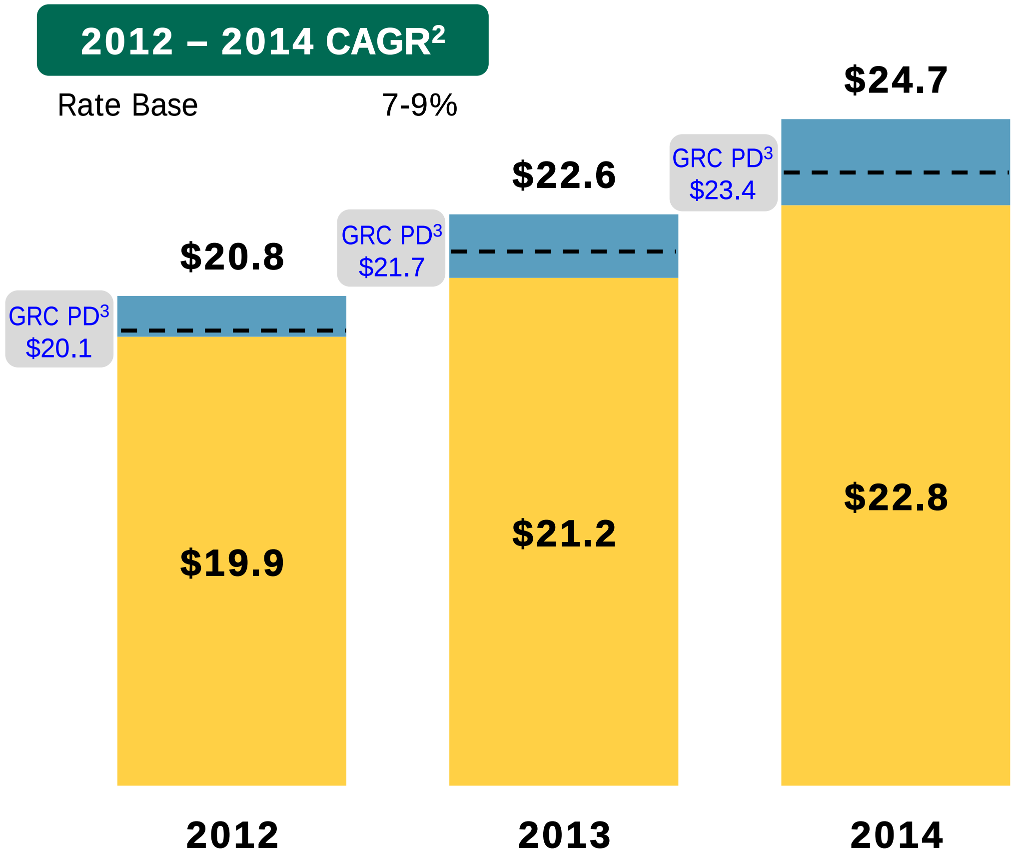
Due to GRC delay, 2012 capital expenditures expected to be below forecast range

1 Forecasted 2012-2014 FERC and CPUC capital spending while final GRC decision is pending, subject to timely receipt of permitting, licensing, and regulatory approvals. Forecast range reflects an 11% variability to annual expenditure levels related to execution risk, scope change, delays, regulatory constraints, and other contingencies. Variability based on average level of actual variability experienced from 2009 through 2011.

2 Capital expenditure forecast updated for GRC Proposed Decision only.

SCE Rate Base Forecast

($ billions)



- Rate base forecast[1] based on 2012 CPUC GRC request and 2012 FERC Formula Rate
- FERC rate base includes CWIP and increases to approximately 20% of 2014 forecast
- Forecast subject to change based on timely receipt of permitting, licensing, capital deployment, and regulatory approvals on capital expenditures
- GRC PD, if adopted, would result in forecasted rate base of $20.1 billion in 2012, $21.7 billion in 2013, and $23.4 billion in 2014

1 Forecast range is weighted-average year basis and includes: (1) forecasted 2012-2014 CPUC and FERC rate base requests; (2) SCE Solar PV program including CPUC approved petition for modification; (3) consolidation of CWIP projects; (4) estimated impact of bonus depreciation provisions. Rate Base forecast reflects SCE Capital Expenditures Forecast range.

2 Forecasted Rate Base and related earnings per share may vary depending on authorized revenues and cost of capital, including financing costs, operating expenses, taxes, and other revenue activities.

3 Based on capital expenditure forecast updated for GRC Proposed Decision only.

SONGS Update

Operational

- SCE submitted CAL response and restart plans for Unit 2 to NRC
  - Operate at 70% power for 5 months with follow up outage and inspection
  - No assurance about NRC review time or approval of restart request
  - Repairs to restart Unit 2 at reduced power levels substantially completed
- Unit 3 will not restart this year
- August 2012, SCE announced plans for downsizing to bring SONGS in line with industry peers
  - $30 million estimated cash severance costs recorded in the third quarter

Financial

- September 2012, SCE submitted $45 million invoice to MHI for some costs through June 30, 2012, for all owners' repair costs
- October 2012, SONGS filed separate proofs of loss for Unit 2 and Unit 3 under NEIL outage policy

Regulatory

- October 2012, CPUC issued Order Instituting Investigation (OII) to consolidate all SONGS issues in related regulatory proceedings and consider appropriate cost recovery
  - All SONGS-related costs after January 1 tracked in separate memorandum account
  - SCE will file its response by November 24 and must also file testimony by December 10 detailing costs subject to refund

EMG Third Quarter Highlights

EPS	Q3 11	Q3 12	Variance
Core[1]	$0.05	$(0.28)	$(0.33)
Non-Core Items[2]	0.05	(0.14)	(0.19)
Basic EPS[1]	**$0.10**	**$(0.42)**	**$(0.52)**

Key Core Earnings Drivers	
Midwest Generation[3]	$(0.21)
EMMT - trading	0.02
Renewable energy projects	(0.01)
Natural gas projects	(0.05)
Higher income taxes and other	(0.08)
Total	$(0.33)

Recent Developments

- September 2012, Homer City entered into Master Transaction Agreement and in October 2012 Plan Support Agreement – discontinued operations accounting treatment beginning third quarter 2012
- Waukegan 7 request to extend unit-specific retrofit requirements from December 31, 2013, to December 31, 2014, granted by IL Pollution Control Board

1 See Non-GAAP Reconciliations and Use of Non-GAAP Financial Measures in Appendix for reconciliation of core earnings per share to basic earnings per share.

2 Homer City's financial results are reported as non-core for both quarters, resulting in a $(0.24) per share loss for the quarter ended September 30, 2012, and earnings of $0.05 per share for the quarter ended September 30, 2011. Non-core items for the quarter ended September 30, 2012, also include a $0.09 per share gain from Edison Capital's sale of its Beaver Valley lease interest, and other.

3 Includes per share impact of unrealized losses of $(0.01) in both periods.

Liquidity Profile

September 30, 2012
($ millions)

Sources	SCE	EME & Subs[2]	Other EMG Subs	EIX parent co. & other
Credit Facility[1]	$2,750	$—	$—	$1,250
Credit Facility (availability)	$2,174	$—	$—	$1,222
Cash & Cash Equivalents	96	698	154	138
Available Liquidity	**$2,270**	**$698**	**$154**	**$1,360**

- Recognized EME tax benefits of $1.0 billion available under EIX tax-allocation agreement
  - EME recognized tax-allocation benefits related to net operating loss carryforwards of $790 million and production tax and other credit carryforwards of $236 million
  - EMG made approximately $185 million tax-allocation payment to EIX. EME expects to receive $160 million tax-allocation payments from EIX during next six months

1 Credit facilities expire May 2017.

2 EME had corporate cash of $627 million at September 30, 2012. Corporate cash is defined as cash and cash equivalents of EME and its subsidiaries that do not have contractual third-party dividend restrictions.

EME Financial Status

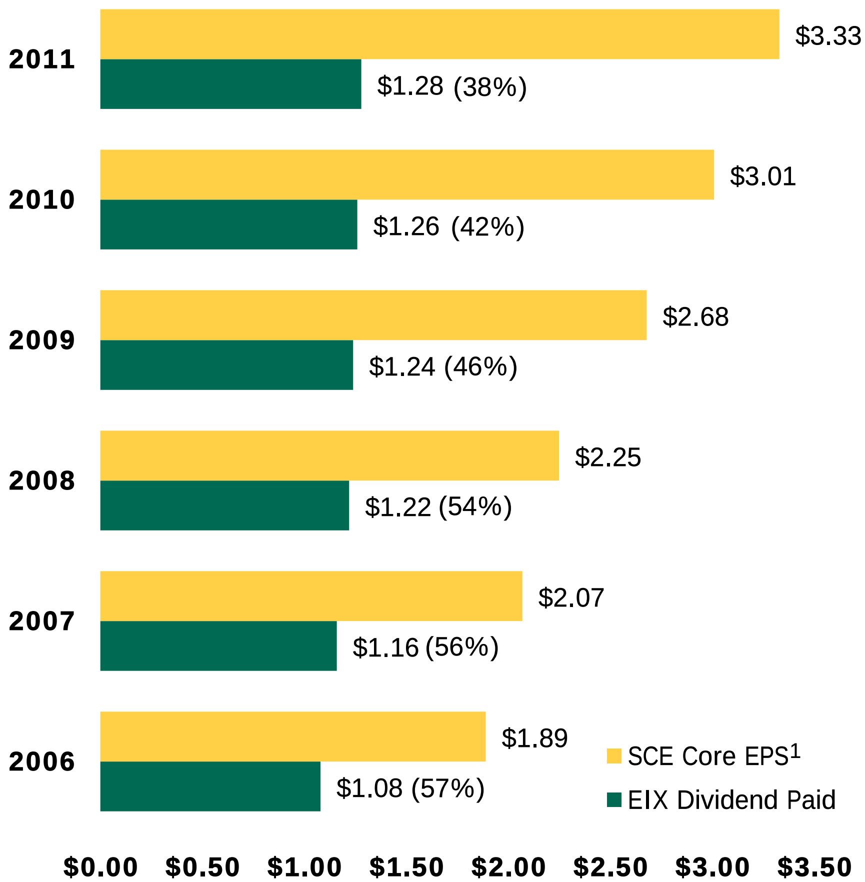
- October 2012, EME and EIX entered into non-disclosure agreements with certain EME unsecured bondholders
- Based on current projections, EME is not expected to have sufficient liquidity to repay $500 million debt obligation due June 2013
- No assurance $97 million interest payments due on 2017, 2019, and 2027 EME unsecured bonds will be paid on November 15
  - ➢ Failure to pay will likely result in EME's filing for protection under Chapter 11 of the U.S. Bankruptcy Code
  - ➢ Chapter 11 filing will trigger cross defaults under other outstanding EME obligations
- October 2012, EME and MWG entered into a non-disclosure agreement with an advisor representing a majority in principal amount of MWG's senior lease obligation bonds

Appendix

Updates Since Our Last Presentation

- Q3 2012 results and standard information
- SCE 2012 CPUC General Rate Case (p. 4)
- SCE Capital Expenditures Forecast (p. 5)
- SCE Rate Base Forecast (p. 6)
- SONGS Update (p. 7) – New Slide
- EME Financial Status (p. 10)
- SCE 2013 Cost of Capital Application (p. 21)
- SONGS – Net Investment and Rate Base (p. 22) – New Slide
- SONGS – Supplemental Data (p. 23)

Dividend Growth



2006 – 2011 CAGR	
SCE Core EPS[1]	12%
EIX Dividend	4%

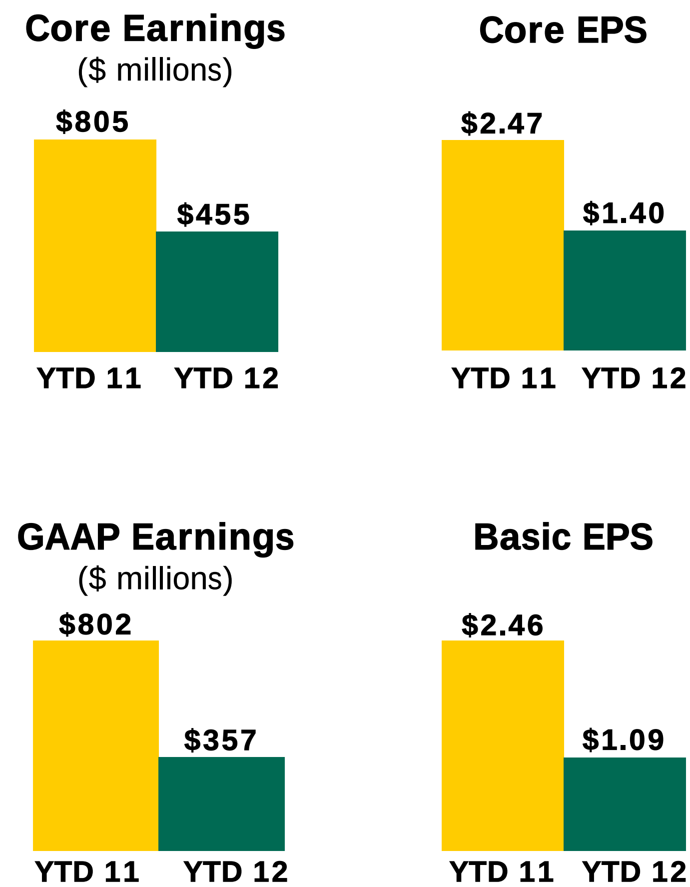
- EIX targets paying out 45 – 55% of SCE earnings
- Dividend not growing at same rate as SCE core earnings and is below target payout ratio due to large utility capital program
- EIX plans to return to target dividend range over time as SCE capital spending program declines from its peak, but there can be no assurance

SCE earnings and rate base growth have expanded faster than EIX's dividend as a result of utility's capital program

1 See Use of Non-GAAP Financial Measures in Appendix for reconciliation of core earnings per share to basic earnings per share.

Year-to-Date Earnings Summary

	YTD 11	YTD 12	Variance
Core EPS[1]			
SCE	$2.57	$2.26	$(0.31)
EMG	(0.04)	(0.71)	(0.67)
EIX parent company and other[2]	(0.06)	(0.15)	(0.09)
Core EPS	**$2.47**	**$1.40**	**$(1.07)**
Non-Core Items			
SCE	$ —	$ —	$ —
EMG[3]	(0.01)	(0.31)	(0.30)
EIX parent company and other	—	—	—
Total Non-Core	$(0.01)	$(0.31)	$(0.30)
Basic EPS	**$2.46**	**$1.09**	**$(1.37)**
Diluted EPS	**$2.45**	**$1.09**	**$(1.36)**



1 See Earnings Non-GAAP Reconciliations and Use of Non-GAAP Financial Measures in Appendix. The impact of participating securities is included in EIX parent company and other and was zero for the year-to-date periods ended September 30, 2012, and September 30, 2011.

2 EIX parent company and other for year-to-date period ended September 30, 2012 includes $(0.09) per share for state income tax adjustments related to prior and future periods.

3 Non-core items for the year-to-date period ended September 30, 2012, include Homer City, Edison Capital asset sale, and other. Non-core items for the year-to-date period ended September 30, 2011, include earnings for Homer City and other.

SCE Year-to-Date Highlights

EPS	YTD 11	YTD 12	Variance
Core[1]	$2.57	$2.26	$(0.31)
Non-Core Items	—	—	—
Basic EPS[1]	**$2.57**	**$2.26**	**$(0.31)**

Key Core Earnings Drivers	
2012 GRC delay items	
Depreciation	$(0.14)
Net interest expense	(0.11)
SONGS	
Inspection and repair	(0.17)
Severance	(0.06)
O&M reductions and other	0.15
Income taxes and other	0.02
Total	$(0.31)

1 See Use of Non-GAAP Financial Measures in Appendix for reconciliation of core earnings per share to basic earnings per share.

EMG Year-to-Date Highlights

EPS	YTD 11	YTD 12	Variance
Core[1]	$(0.04)	$(0.71)	$(0.67)
Non-Core Items[2]	(0.01)	(0.31)	(0.30)
Basic EPS[1]	**$(0.05)**	**$(1.02)**	**$(0.97)**

Key Core Earnings Drivers	
Midwest Generation[3]	$(0.48)
Renewable energy projects	(0.01)
Natural gas projects	(0.07)
Higher net interest expense	(0.02)
Higher income taxes and other	(0.09)
Total	$(0.67)

1 See Use of Non-GAAP Financial Measures in Appendix for reconciliation of core earnings per share to basic earnings per share.

2 Homer City's financial results are reported as non-core for both periods, resulting in a $(0.40) per share loss for the year-to-date period ended September 30, 2012, and zero per share for the year-to-date period ended September 30, 2011. Non-core items for the year-to-date period ended September 30, 2012, also include $0.09 per share gain from Edison Capital's sale of its Beaver Valley lease interest, and other.

3 Includes impact of unrealized losses of $(0.01) per share for the year-to-date period ended September 30, 2012, and losses of $(0.01) per share for the year-to-date period ended September 30, 2011.

Debt Maturity Profiles

September 30, 2012
($ millions)

Calendar Year	2012	2013	2014	2015
Short- and Long-Term Debt Maturities				
SCE	$380	$—	$1,200	$300
EME[1,2]	27	591	294	72
EIX	28	—	—	—

1 Includes project finance and other non-recourse debt.
2 Assumes conversion of $340 million outstanding Walnut Creek construction loan to term loan in 2013.

Non-GAAP Reconciliations

($ millions)

Reconciliation of EIX Core Earnings to EIX GAAP Earnings

Earnings Attributable to Edison International	Q3 11	Q3 12	YTD 11	YTD 12
Core Earnings[1]				
SCE	$406	$363	$838	$736
EMG	18	(92)	(14)	(233)
EIX parent company and other	(13)	(36)	(19)	(48)
EIX Core Earnings	**$411**	**$235**	**$805**	**$455**
Non-core items				
EMG – Sale of Beaver Valley lease interest	$ —	$31	$ —	$31
Earnings (loss) from discontinued operations[2,3]				
EMG – Homer City	15	(11)	—	(50)
EMG – Homer City impairment and other charges	—	(68)	—	(81)
EMG – Other	—	3	(3)	2
Total Non-core items	15	(45)	(3)	(98)
EIX GAAP Earnings	**$426**	**$190**	**$802**	**$357**

1 See Use of Non-GAAP Financial Measures.

2 Homer City's financial results are reported as non-core for both quarters, resulting in a $(79) million loss for the quarter ended September 30, 2012, and earnings of $15 million for the quarter ended September 30, 2011.

3 Homer City's financial results are reported as non-core for both periods, resulting in a $(131) million loss for the year-to-date period ended September 30, 2012, and zero per share for the year-to-date period ended September 30, 2011.

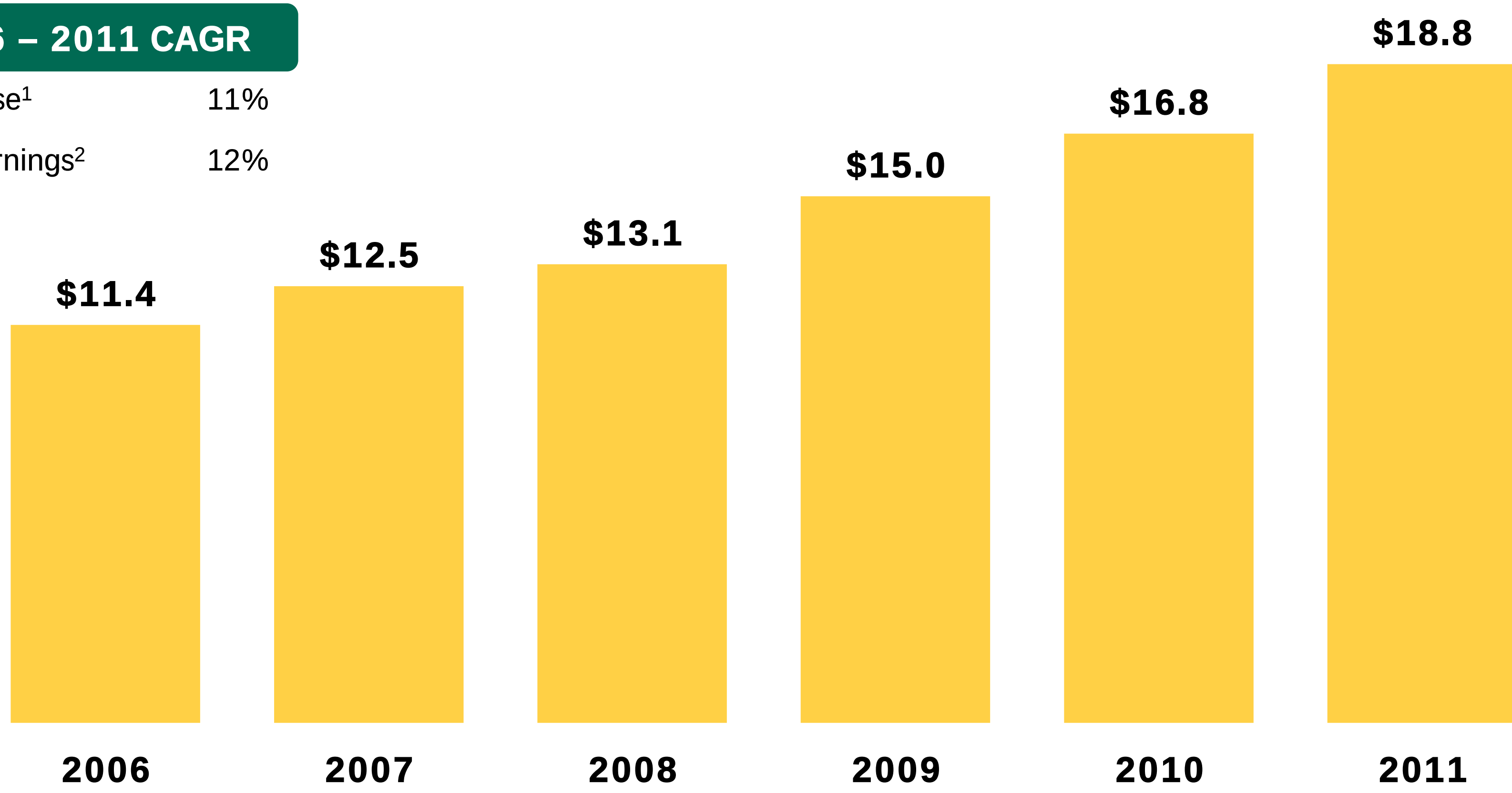
SCE Appendix

SCE Historical Rate Base and Core Earnings

($ billions)

2006 – 2011 CAGR

Rate Base[1]	11%
Core Earnings[2]	12%



Core Earnings[2]	$1.89	$2.07	$2.25	$2.68	$3.01	$3.33

1 Recorded rate base, year-end basis.
2 See Non-GAAP Reconciliations and Use of Non-GAAP Financial Measures in Appendix.

SCE 2013 Cost of Capital Application

- On April 20, 2012, SCE filed its application to set the capital structure and cost of capital (A.12-04-015)
- Requested Return on Common Equity (ROE) of 11.1%:
  - ➢ Capital needs are relatively high compared to other electrics
  - ➢ Financial strength needed to attract capital for aggressive State policy goals
  - ➢ Relatively lower ROE in other jurisdictions does not reflect SCE business and financial risks

Proposed Phase I Schedule	
Utilities Supplemental Testimony	June 28
Intervenor Testimony	August 6
Rebuttal Testimony	August 29
Hearings	September 14 – 28
Proposed Decision	November 29
Final Decision	December 20

Proposed Phase II Schedule	
Utilities Supplemental Testimony	Oct. 26
Intervenor Testimony	Nov. 30
Rebuttal Testimony	Dec. 14
Hearings	Jan. 14 – 15, 2013
Proposed Decision	March, 2013
Final Decision	April, 2013

Phase		Current	Proposed	2013 Revenue Impact
Phase I	Capital Structure	• Long Term Debt – 43% • Preferred Debt – 9% • Equity – 48%	• Long Term Debt – 43% • Preferred Debt – 9% • Equity – 48%	• None
Phase I	Cost of Capital	• Long Term Debt – 6.22% • Preferred Debt – 6.01% • Equity – 11.5%	• Long Term Debt – 5.49% • Preferred Debt – 5.79% • Equity – 11.1%	• $132 million reduction based on 2012 GRC request, or 0.2 cents/kWh
Phase II	Adjustment Mechanism	Annual ROE trigger mechanism: • Moody's Baa bond index 12-month average • ½ difference adjustment when 1 percentage point deadband is exceeded	• Continue annual trigger mechanism for 2014 and 2015	• None

SONGS – Net Investment and Rate Base

September 30, 2012
($ millions)

	Unit 2	Unit 3	Common Plant	Total
Net Investment				
Net plant in service[1]	$593	$418	$261	$1,272
Materials and supplies	—	—	99	99
Construction work in progress	77	141	76	294
Nuclear fuel	153	212	101	466
Total Net Investment[1]	**$823**	**$771**	**$537**	**$2,131**
Rate base				
Net plant in service[1]	$593	$418	$261	$1,272
Materials and supplies	—	—	99	99
Accumulated deferred income taxes	(95)	(45)	(66)	(206)
Amounts in Rate Base	**$498**	**$373**	**$294**	**$1,165**

1 Net of accumulated depreciation. Includes Construction Work in Progress, nuclear fuel, and materials and supplies.

SONGS – Supplemental Data

September 30, 2012
($ millions)

2012 Outage Impacts (SCE share)	
Inspection & Repair Costs – Incurred	$96
Net Market Costs – Incurred[1]	$221
Regulatory (SCE share)	
Steam Generator Replacement (SGR) Project – Approved[2]	$665
SGR Project – Incurred[3]	$594
Estimated 2012 Annual Revenue Requirement[4]	$820
Physical (Total)	
SCE Ownership	78.21%
Capacity (MW)	2,150
2011 Generation (million kWh)	18,097

1 Energy and capacity net of avoided nuclear fuel costs. Represents about 7% of SCE's total fuel and purchased power expense incurred year to date September 30, 2012.
2 Adjusted for inflation from $525 million (2004$) authorized by CPUC in 2005.
3 Includes $95 million CWIP primarily related to disposal of old steam generators.
4 Includes $170 million nuclear fuel-related and decommissioning costs, and $650 million direct operations and maintenance costs, depreciation and return on investment.

SONGS – Warranty and Insurance

MHI Warranty

- 20-year warranty with Mitsubishi Heavy Industries
  - Repair or replace defective items
  - Specified damages for certain repairs
  - $138 million liability limit and excludes consequential damages (e.g., replacement power)
  - Limits subject to applicable exceptions
  - September 2012, SCE submitted $45 million invoice to MHI for some costs through June 30, 2012 for all owners' repair costs

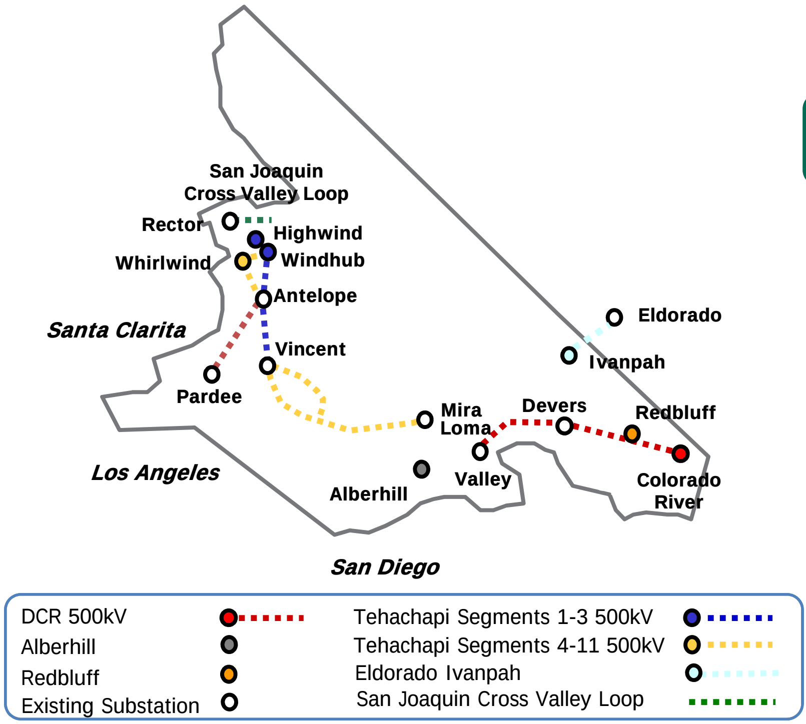
NEIL Insurance

- Property damage and outage insurance through Nuclear Electric Insurance Limited ("NEIL")
  - "Accidental Property Damage" – $2.5 million deductible; $2.75 billion liability limit
  - Outage from "Accidental Property Damage" – up to $3.5 million per week for each unit after 12-week deductible period ($2.8 million per unit per week if both are out due to same "accident"); $490 million limit per unit ($392 million each if both units are out due to the same "accident")
  - Exclusions and limitations may reduce or eliminate coverage
  - Proof of loss must be submitted within 12 months of damage or outage
  - October 2012, SONGS filed separate proofs of loss for Unit 2 and Unit 3 under NEIL outage policy

There is no assurance that SCE will recover all of its applicable costs pursuant to these arrangements

SCE Transmission Program

September 30, 2012



Project Name	Project Lifecycle Phase	In Service Date	Direct Project Costs[1]	% of Spend Complete	2012-2014 Forecast[1]
Tehachapi 1-11[2,3]	Construction	2015	$2,500	69%	$904
Devers-Colorado River[3]	Construction	2013	860	33%	709
Eldorado-Ivanpah[4]	Engineering / Construction	2013	444	11%	417
Red Bluff	Construction	2013	234	28%	220
Alberhill	Licensing	2015	315	8%	242
San Joaquin Cross Valley Loop	Engineering / Construction	2014	190	14%	170

Transmission expenditures are needed to improve system reliability and increase access to renewable energy

1 FERC and CPUC jurisdictional assets. Direct expenditures include direct labor, land and contract (materials & contractor) costs incurred for each project and excludes allocated overhead costs included in the SCE Capital Expenditures Forecast for 2012 - 2014. Subject to timely receipt of permitting, licensing, and regulatory approvals.
2 Tehachapi segments 1-3A were energized and in-service in 2009. The remainder is under construction and will be phased into service through 2015.
3 SCE has experienced significant cost pressures on its Tehachapi and Devers-Colorado River Transmission Projects, primarily related to environmental monitoring and mitigation costs, scope changes, and schedule delays. Related CPUC filings will be updated when final engineering is completed.
4 Eldorado-Ivanpah Project received CPUC approval at $411 million related to reduced contingency. SCE has the ability to file an updated cost when final engineering is completed.

Other SCE Key Regulatory Events

	Case Number	Date of Filing	Status	Next Milestone
FERC Formula Rate Filing	ER11-3697	06/03/11	Settlement discussions on 2012 formula rate filing in progress	Next settlement conference to be held on December 5th and 6th, 2012
		12/05/11	FERC rejected SCE's request for rehearing on ROE, and SCE has initiated court appeal	SCE filed reply brief on ROE at DC Circuit on August 20 and scheduling of oral argument pending
		09/14/12	2013 formula rate update filed; parties filed protests and motions to consolidate on 10/5/12	FERC hearing/settlement order expected by mid-November
Tehachapi Transmission	A. 07-06-031	06/28/07	CPUC restrictions during evaluation of Petition for Modification and Assigned Commissioner's Ruling regarding Chino Hills continue to impact construction on Segments 7 and 8	CPUC approval for Petition for Modification for aviation marking and lighting expected Q2 2013; Response to Scoping Memo and Assigned Commissioner Ruling due February 2013
Devers-Colorado River Transmission	A. 05-04-015	04/11/05	Construction began January 2012	Revised costs to be filed with CPUC in Q4 2012
Eldorado-Ivanpah Transmission	A. 09-05-027	05/28/09	Nevada PUC PTC approval obtained March 2012. Construction commenced March 2012	Forecast in-service July 2013
Alberhill	A. 09-09-022	09/30/09	Permit to Construct filed September 2009 converted to a CPCN filing March 2010. Amended Proponent's Environmental Assessment (PEA) per CPUC request submitted April 2011	Draft Environmental Impact Report (EIR) expected from the CPUC Q4 2012

SCE Results of Operations

($ millions)

	Three Months Ended Sept 30, 2011			Three Months Ended Sept 30, 2012		
	Utility Earning Activities	Utility Cost-Recovery Activities	Total Consolidated	Utility Earning Activities	Utility Cost-Recovery Activities	Total Consolidated
Operating Revenue	$1,759	$1,627	$3,386	$1,754	$1,977	$3,731
Fuel and purchased power	—	1,374	1,374	—	1,694	1,694
Operation and maintenance	566	253	819	623	283	906
Depreciation, decommissioning and amortization	358	—	358	399	—	399
Property and other taxes	71	—	71	73	—	73
Total operating expenses	995	1,627	2,622	1,095	1,977	3,072
Operating income	**764**	**—**	**764**	**659**	**—**	**659**
Net interest expense and other	(98)	—	(98)	(95)	—	(95)
Income before income taxes	**666**	**—**	**666**	**564**	**—**	**564**
Income tax expense	245	—	245	176	—	176
Net income	**421**	**—**	**421**	**388**	**—**	**388**
Dividends on preferred and preference stock not subject to mandatory redemption	15	—	15	25	—	25
Net income available for common stock	**$406**	**$—**	**$406**	**$363**	**$—**	**$363**
Core Earnings[1]			$406			$363
Non-Core Earnings[1]:						
Tax settlement			—			—
Total SCE GAAP Earnings			**$406**			**$363**

1 See Use of Non-GAAP Financial Measures.

SCE Core EPS Non-GAAP Reconciliations

Reconciliation of SCE Core Earnings Per Share to SCE GAAP Earnings Per Share

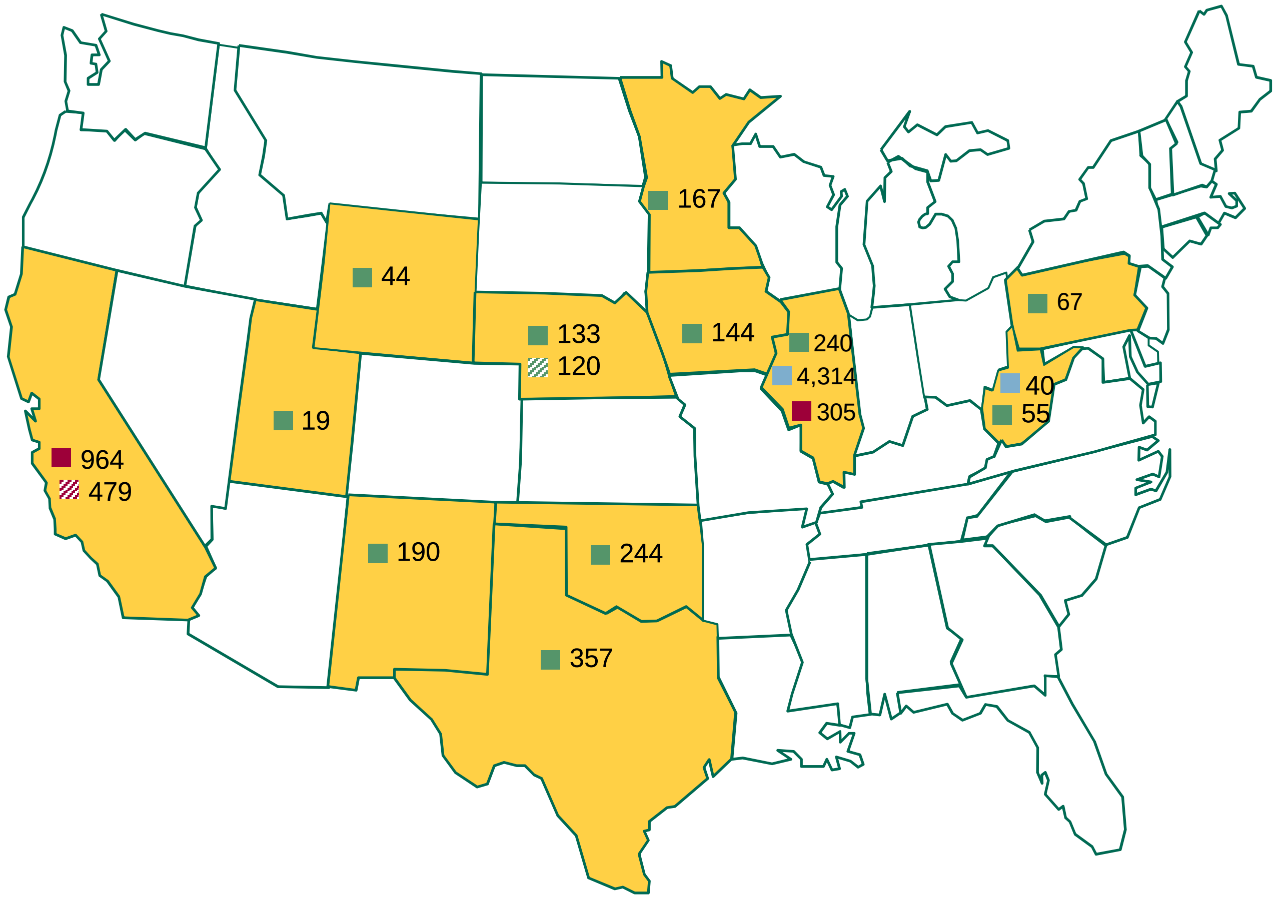
Earnings Per Share Attributable to SCE	2006	2007	2008	2009	2010	2011	CAGR
Core EPS[1]	**$1.89**	**$2.07**	**$2.25**	**$2.68**	**$3.01**	**$3.33**	**12%**
Non-core items							
Tax settlement	—	—	—	0.94	0.30	—	
Health care legislation	—	—	—	—	(0.12)	—	
Regulatory and tax items	0.40	0.10	(0.15)	0.14	—	—	
Generator settlement/refund incentive	0.09	—	—	—	—	—	
Total non-core items	0.49	0.10	(0.15)	1.08	0.18	—	
Basic EPS	**$2.38**	**$2.17**	**$2.10**	**$3.76**	**$3.19**	**$3.33**	**7%**

1 See Use of Non-GAAP Financial Measures.

EME Appendix

EME Business Platform

September 30, 2012



Owned and Operated[1]	MW	%
Coal[2]	4,354	59
Natural Gas	1,269	17
Wind[3]	1,660	22
Other	153	2
Total	7,436	100

Under Construction	MW
Wind	120
Natural Gas[4]	479

Wind Development	MW
Pipeline[5]	~700

1 Natural gas includes oil-fired; other includes Doga in Turkey (144 MW) and Huntington biomass (9 MW), which are not shown.
2 Excludes Fisk (326 MW) and Crawford (532 MW) stations shut down in September 2012.
3 Includes operating projects reflected on a net basis based on EME's interest to reflect Capistrano Wind Partners (CWP) closing in the quarter ended March 31, 2012.
4 Deliveries under the power sales agreement are expected to commence in 2013.
5 Owned or under exclusive agreement.

Midwest Generation (Illinois)

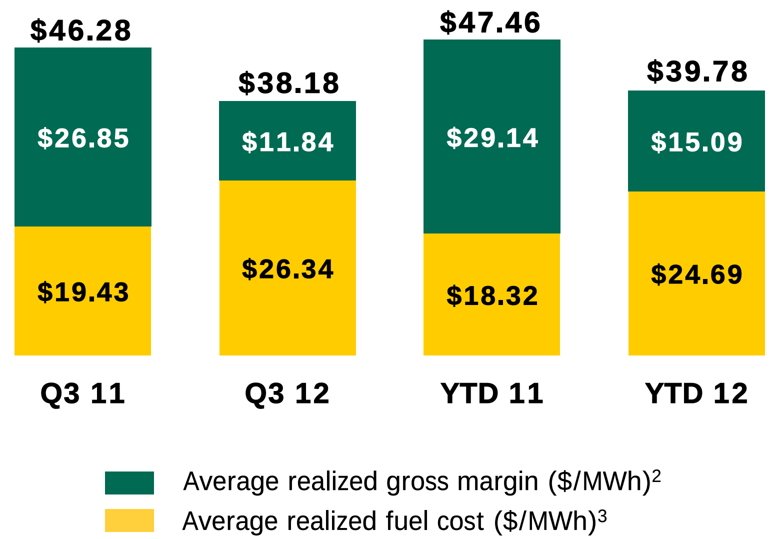
Operational Statistics

	Q3 11	Q3 12	YTD 11	YTD 12
Total Generation (GWh)	7,957	6,653	20,987	17,459
Forced Outage Rate	7.2%	5.4%	5.9%	4.8%
Capacity Factor	69.8%	62.2%	62%	52.5%
Equivalent Availability	89.4%	92.5%	80%	83.5%
Load Factor	78.1%	67.2%	77.5%	62.9%
Flat energy price NI Hub ($/MWh)	$37.33	$32.28	$35.30	$28.56

4,314 MW[4] – Four mid-merit facilities

Utilize Powder River Basin (PRB) coal

All-in Average Realized Prices[1,3]



1 Includes the price of energy, capacity, ancillary services, etc.
2 Average realized gross margin is equal to all-in average realized price less average fuel and emission costs.
3 See Other Non-GAAP Reconciliations and Use of Non-GAAP Financial Measures in Appendix.
4 Excludes Fisk (326 MW) and Crawford (532 MW) stations shut down in September 2012.

Midwest Generation Hedging & Capacity Sales[1]

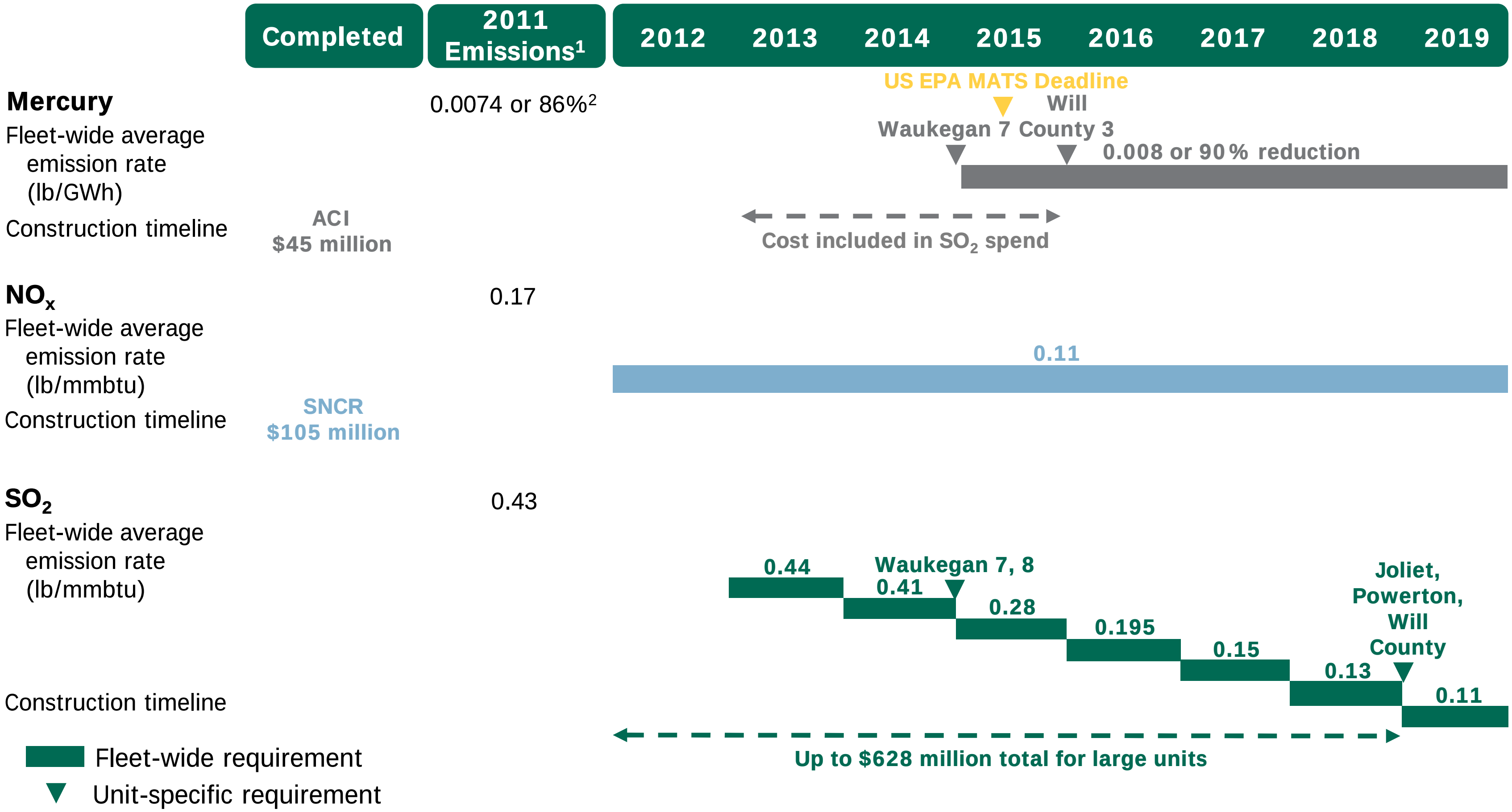
September 30, 2012

	Remainder of 2012	Net[2] Change From Q2	2013	Net[2] Change From Q2	2014	Net[2] Change From Q2
Total GWh (NI, AEP/Dayton, and Indiana Hubs)	2,028	(1,610)	3,615	2,595	—	—
Average price ($/MWh)	$37.53	$(0.71)	$36.55	$(3.87)	—	—
Coal under contract (millions of tons)[3]	4.9	(4.5)	11.1	0.5	9.8	—

	RPM Capacity Sold in Base Residual Auction		Other Capacity Sales, Net of Purchases		Aggregate
	MW	Price per MW-day	MW	Average Price per MW-day	Average Price per MW-day
October 1, 2012 to May 31, 2013	4,704	$16.46	(450)	$15.67	$16.54
June 1, 2013 to May 31, 2014	4,650	$27.73	(2,430)	$7.01	$50.40
June 1, 2014 to May 31, 2015	4,625	$125.99	(700)	$5.54	$147.47
June 1, 2015 to May 31, 2016	3,620	$136.00	—	—	$136.00

1 See "Market Risk Exposures – Commodity Price Risk" in EME's quarterly report on Form 10-Q for complete descriptions and definitions of hedging programs.
2 Change from Q2 for 2012 includes 69 GWh of new hedges.
3 In July 2012 Midwest Generation agreed to sell one million tons of coal scheduled to be delivered in the second half of 2012 in order to better manage coal inventories. This transaction resulted in a $6 million loss the quarter ended September 30, 2012.

EME 2006 Illinois CPS Agreement



1 Based on tests administered closest to year ended December 31, 2011, and submitted to Illinois EPA for compliance.

2 Actual mercury requirement for 2011 under the CPS was 5 lb/MMacf ACI injection, which has been met. Percent reduction requirement is based on mercury concentration in coal before and after treatment system. Reduction is across all units, including Waukegan 7 and Will County 3, which will require particulate removal upgrades to meet fleet-wide emission and unit-specific requirements. Midwest Generation believes that currently installed ACI and particulate removal equipment is sufficient to achieve or exceed the requirements outlined in the final MATS Rule.

Midwest Generation Compliance Cost

Unit	Operating Capacity (MW)	2011 Generation (GWh)	% of Regional Fleet	Total Large Unit Est. Capex ($MM)[2]	Total Small Unit Est. Capex ($MM)[2]
Waukegan 7, 8	689	3,898	13.9%		$160
Joliet 6	290	1,675	5.9%		$75
Joliet 7, 8	1,036	5,907	21.0%	$200	
Will County 3, 4[1]	761	3,492	12.4%	$194	
Powerton 5, 6	1,538	9,184	32.7%	$234	
Total	**4,314**	**24,156**		**$628**	**$235**

1 Will County 3 requires particulate removal upgrades in 2015 to comply with the CPS requirements.

2 No decision has been made to retrofit particular units. Capital expenditure forecast provides for large unit retrofits. It is less likely that retrofits will be made to Joliet 6 and the Waukegan Station.

EME Wind Strategy & Financing

Refocused Wind Strategy

- Capistrano Wind Partners (CWP) formed February 13, 2012, by EME, TIAA-CREF, CIRI (an Alaskan native corporation). $460 million commitment for wind development:
  - Operating projects transferred – Cedro Hill, Texas (150 MW) and Mountain Wind I and II, Wyoming (141 MW) – EME received $242 million in March 2012
  - Projects to be transferred after completion – Broken Bow I, Nebraska (80 MW) and Crofton Bluffs, Nebraska (40 MW) – EME expects to receive $140 million upon transfer of completed projects
  - EME retains an economic interest and will continue to operate and consolidate projects
- 700 MW development pipeline
- New wind projects to be developed or acquired only with third-party capital

Other Recent Wind Developments

- Continuing Big Sky vendor dispute regarding timing of repayment of $206 million in project debt; no recourse to EME
- Broken Bow I, Nebraska (80 MW) and Crofton Bluffs, Nebraska (40 MW) expected completion in fourth quarter 2012

Wind Project Financing Capacity

- 575 MW not financed:
  - 387 MW contracted[1]
  - 188 MW merchant – Goat Wind, Texas (150 MW), Lookout, Pennsylvania (38 MW)

1 Includes Storm Lake project (108 MW) that was impaired in the quarter ended December 31, 2011.

EME Capital Expenditures

September 30, 2012
($ millions)

	2011[1]	2012[2]	2013	2014
Midwest Generation				
Environmental expenditures[3]	$82	$26	$112	$311
Plant capital expenditures	27	8	50	16
Walnut Creek Project[4]	269	206	63	—
Renewable Energy Projects				
Capital & construction	267	112	1	2
Turbine commitments	8	—	—	—
Other capital expenditures	7	19	19	15
Total	**$660**	**$371**	**$245**	**$344**

1 2011 expenditures shown on accrual basis.
2 Includes actual expenditures plus estimated remaining for 2012.
3 Projected expenditures to retrofit Powerton Units 5 and 6, Joliet Units 7 and 8, and Will County Units 3 and 4. No decisions have been made to retrofit particular units.
4 Total project costs are estimated to be $611 million. Capital expenditures in the above table exclude $72 million of interest and expenses during construction, financing costs, and costs incurred before 2011.

EMG[1] – Adjusted EBITDA

September 30, 2012
($ millions)

Reconciliation to Earnings	Q3 11	Q3 12	YTD 11	YTD 12
Earnings	$33	$(137)	$(17)	$(331)
Addback (Deduct):				
Discontinued operations	(15)	76	3	129
Income from continuing operations	18	(61)	(14)	(202)
Interest expense	82	83	243	253
Interest income	0	(1)	(3)	(2)
Income taxes (benefits)	(11)	(15)	(102)	(169)
Depreciation and amortization	72	67	213	202
EBITDA[1]	**$161**	**73**	**$337**	**82**
Production tax credits	10	12	47	48
Addback:				
Gain on sale of Beaver Valley	—	(67)	—	(67)
Loss on sale/disposal of assets	—	2	8	7
Adjusted EBITDA	**$171**	**$20**	**$392**	**$70**

1 Earnings are attributable to Edison Mission Group and include impact of Edison Capital.
2 See Use of Non-GAAP Financial Measures.

EME Other Non-GAAP Reconciliations

($ millions)

Reconciliation of Midwest Generation Operating Revenues and Fuel Costs to All-in Average Realized Price / MWh and Average Realized Fuel Cost / MWh

	Midwest Generation			
	Q3 11	Q3 12	YTD 11	YTD 12
Generation (GWh)	7,957	6,653	20,987	17,459
Operating revenues	$366	$253	$997	$699
Less: Unrealized (gains) losses	3	5	1	2
Other revenues	(1)	(4)	(2)	(6)
Realized revenues	$368	$254	$996	$695
All-in average realized price/MWh	$46.28	$38.18	$47.46	$39.78
Fuel costs	$157	$183	$390	$443
Add back: Unrealized gains (losses)	(4)	2	(6)	(2)
Cost of coal sales	0	(10)	0	(10)
Realized fuel costs	$153	$175	$384	$431
Average realized fuel cost/MWh	$19.43	$26.34	$18.32	$24.69

Reconciliation of Midwest Generation Operating Revenues to Segment Revenues and Fuel Costs

	Q3 11	Q3 12	YTD 11	YTD 12
Operating revenues				
Midwest Generation	$366	$253	$997	$699
Renewable projects	44	47	155	182
Other revenues	27	40	120	126
Segment revenues as reported	$437	$340	$1,272	$1,007
Fuel Costs				
Midwest Generation	$157	183	$390	443
Other revenues	4	4	12	15
Segment revenues as reported	$161	$187	$402	$458

Use of Non-GAAP Financial Measures

Edison International's earnings are prepared in accordance with generally accepted accounting principles used in the United States and represent the company's earnings as reported to the Securities and Exchange Commission. Our management uses core earnings and EPS by principal operating subsidiary internally for financial planning and for analysis of performance. We also use core earnings and EPS by principal operating subsidiary when communicating with analysts and investors regarding our earnings results and outlook, to facilitate the company's performance from period to period.

Core earnings is a Non-GAAP financial measure and may not be comparable to those of other companies. Core earnings and core earnings per share are defined as GAAP earnings and basic earnings per share excluding income or loss from discontinued operations and income or loss from significant discrete items that management does not consider representative of ongoing earnings. GAAP earnings refer to net income attributable to Edison International common shareholders or attributable to the common shareholders of each subsidiary. EPS by principal operating subsidiary is based on the principal operating subsidiaries' net income attributable to the common shareholders of each subsidiary, respectively, and Edison International's weighted average outstanding common shares. The impact of participating securities (vested stock options that earn dividend equivalents that may participate in undistributed earnings with common stock) for each principal operating subsidiary is not material to each principal operating subsidiary's EPS and is therefore reflected in the results of the Edison International holding company, which we refer to as EIX parent company and other.

EBITDA is defined as earnings before interest, income taxes, depreciation and amortization. Adjusted EBITDA includes production tax credits from EME's wind projects and excludes amounts from gain on the sale of assets, loss on early extinguishment of debt and leases, and impairment of assets and investments. Our management uses Adjusted EBITDA as an important financial measure for evaluating EME which represents substantially all of the EMG business segment.

The average realized energy price and average realized fuel cost is a non-GAAP performance measure since such statistical measures exclude unrealized gains or losses recorded as operating revenues and unrealized gains or losses recorded as fuel expenses. Management believes that the average realized energy price and average realized fuel cost is more meaningful for investors as it reflects the impact of hedge contracts at the time of actual generation in period-over-period comparisons or as compared to real-time market prices.

A reconciliation of Non-GAAP information to GAAP information, including the impact of participating securities, is included either on the slide where the information appears or on another slide referenced in this presentation.