EDISON INTERNATIONAL®

Business Update

September 2014

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), 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 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.

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SCE Highlights

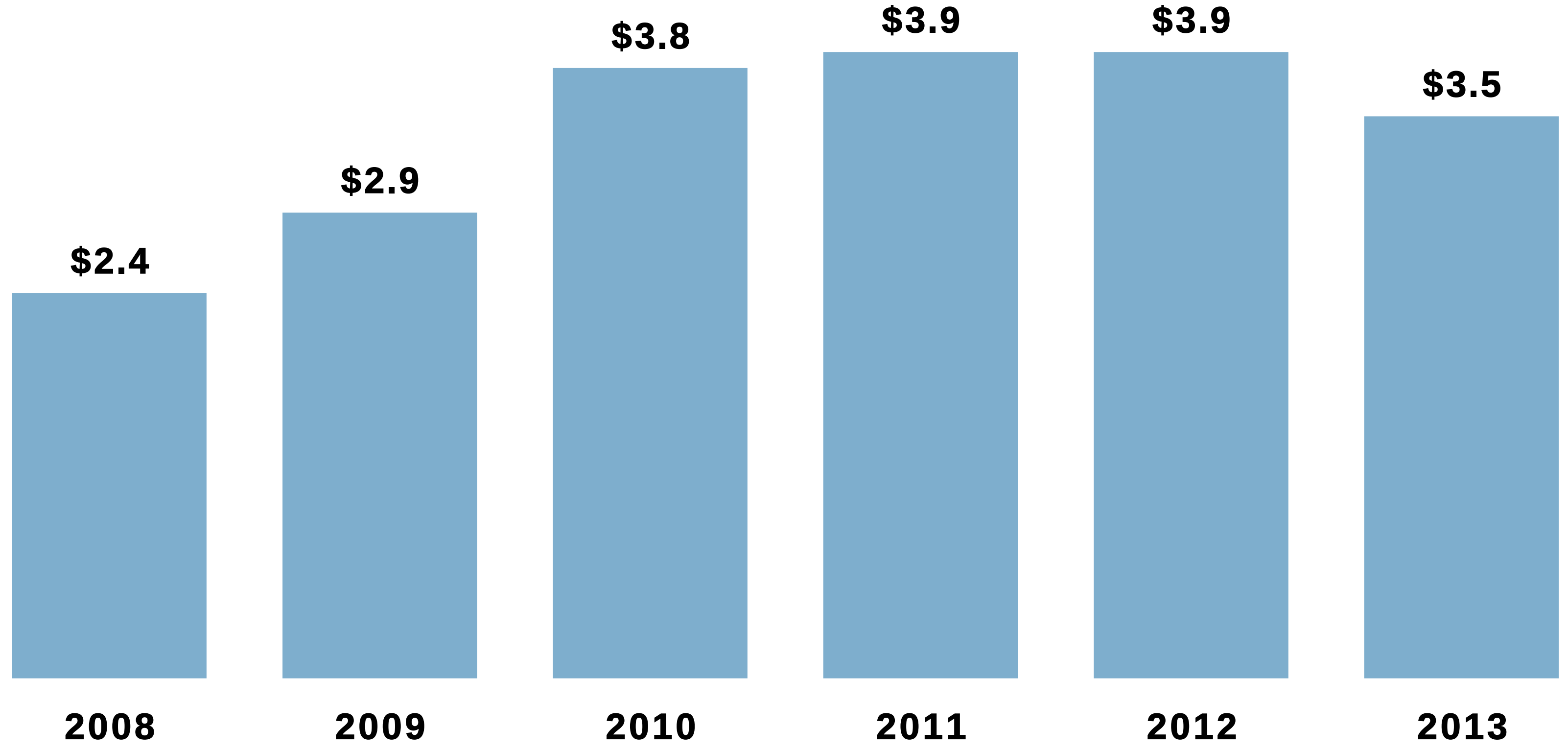
- One of the nation's largest electric utilities
  - ➢ Nearly 14 million residents in service territory
  - ➢ Approximately 5 million customer accounts
  - ➢ 50,000 square-mile service area
- Significant infrastructure investments:
  - ➢ 1.4 million power poles
  - ➢ 700,000 transformers
  - ➢ 103,000 miles of distribution and transmission lines
  - ➢ 3,200 MW owned generation
- 7 – 9% projected average annual rate base growth 2014 – 2017 driven by:
  - ➢ System reliability and infrastructure replacement
  - ➢ California Renewables Portfolio Standard
  - ➢ Technology improvements

SCE Decoupled Regulatory Model

Regulatory Model	Key Benefits
Decoupling of Regulated Revenues from Sales	• SCE earnings are not affected by changes in retail electricity sales • Differences between amounts collected and authorized levels are either billed or refunded to customers • Promotes energy conservation • Stabilizes revenues during economic cycles
Major Balancing Accounts • Fuel • Purchased power • Energy efficiency • Pension-related contributions	• Trigger mechanism for fuel and purchased power adjustments at 5% variance level • Utility cost-recovery via balancing accounts represented over 50% of 2013 costs
Advanced Long-Term Procurement Planning	• Sets prudent upfront standards allowing greater certainty of cost recovery (subject to reasonableness review)
Forward-looking ratemaking	• Three-year rate case and cost of capital cycles

SCE Historical Capital Expenditures

($ billions)



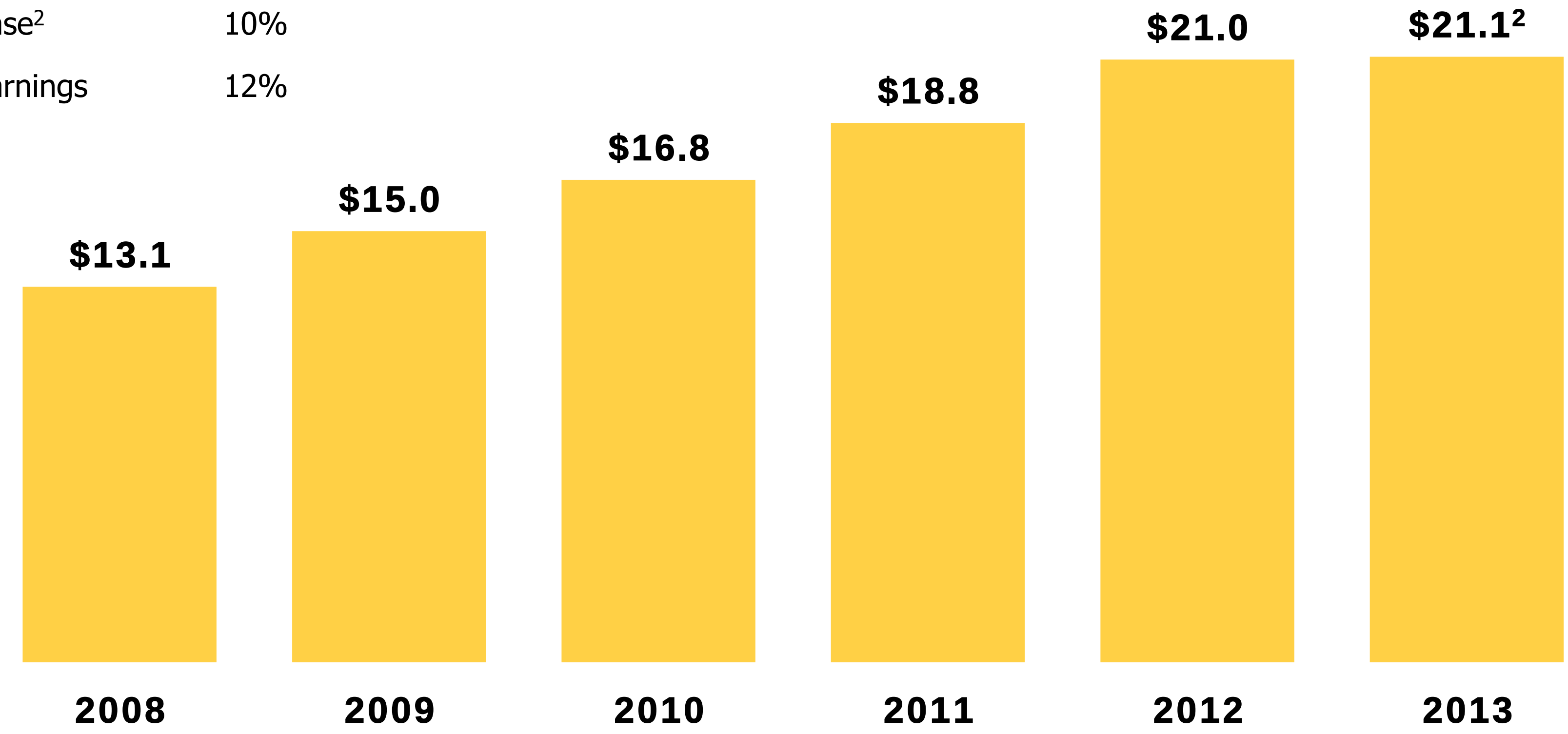
Note: 2013 distribution reliability spend up $300 million, offset by completion of SmartConnect in 2012 ($300 million); lower FERC ($300 million) and lower SONGS ($100 million)

SCE Historical Rate Base and Core Earnings

($ billions)

2008 – 2013 CAGR

Rate Base[2]	10%
Core Earnings	12%

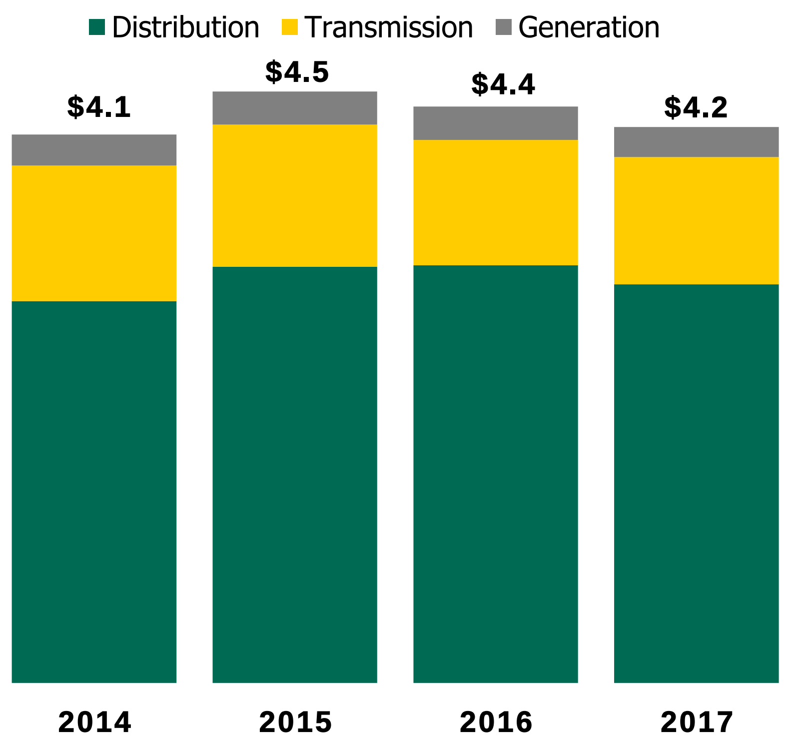


	2008	2009	2010	2011	2012	2013
Core Earnings	$2.25	$2.68	$3.01	$3.33	$4.10	$3.88

1 Recorded rate base, year-end basis. See Earnings Non-GAAP Reconciliations and Use of Non-GAAP Financial Measures in Appendix.
2 2013 rate base excludes San Onofre Generating Station (SONGS)

SCE Capital Expenditures Forecast

($ billions)



	2014	2015	2016	2017	2014-17 Total
Requested	$4.1	$4.5	$4.4	$4.2	$17.2
Range	$3.6	$3.9	$3.9	$3.7	$15.1

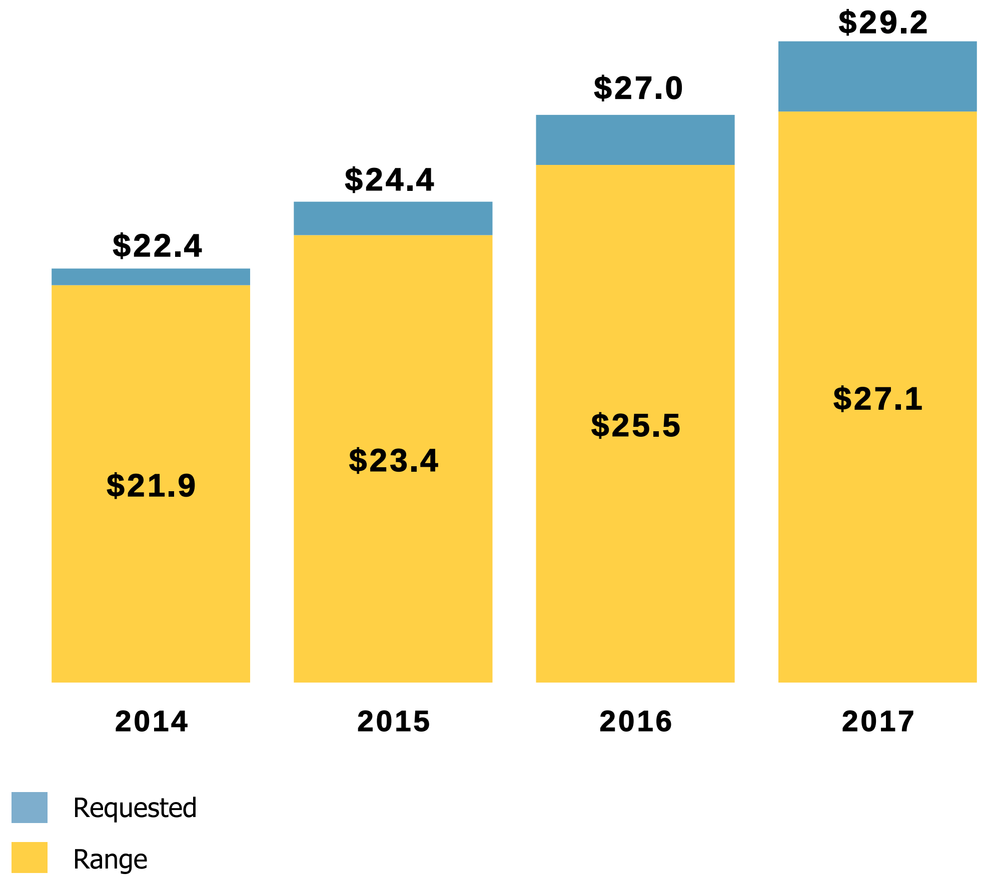
$15.1 – $17.2 billion forecasted capital program 2014 – 2017

- Capital expenditures forecast reaffirmed
- CPUC GRC focused on infrastructure replacement
- Includes Tehachapi scope changes for FAA requirements and $360 million estimate for Chino Hills undergrounding

Note: forecasted capital spending subject to timely receipt of permitting, licensing, and regulatory approvals. Forecast range reflects an average variability of 12%.

SCE Rate Base Forecast

($ billions)



7 – 9% CAGR projected rate base 2014 – 2017

- Growth rate reaffirmed
- Driven by infrastructure replacement, reliability investments, and public policy requirements
- FERC rate base includes CWIP and is approximately 22% of 2014 rate base forecast, increasing to 24% in 2017
- Excludes SONGS rate base

Note: Weighted-average year basis, including forecasted 2014 FERC and 2015-2017 CPUC rate base requests and consolidation of FERC CWIP projects. Rate Base forecast range reflects capital expenditure forecast range.

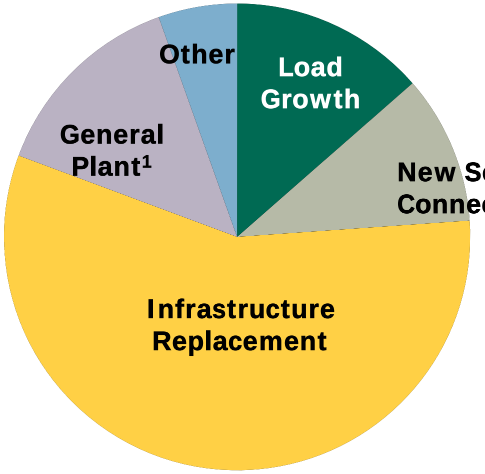
SCE System Investments

($ millions)

Distribution

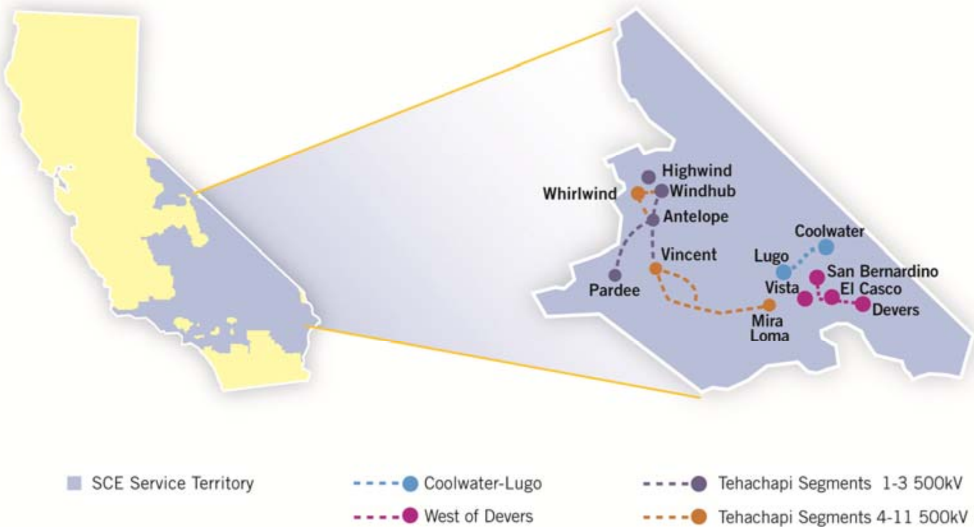
- Aging system reaching equilibrium replacement rate
- 2015 GRC request includes ~120% increase in infrastructure replacement

2015 – 2017 Requested GRC Expenditures for Distribution Assets $9.3 Billion



Transmission

- Large transmission projects:
  - Tehachapi – $3.2 billion total project cost; 2016-17 in service date
  - Coolwater-Lugo – $0.8 billion total project cost; 2018 in service date
  - West of Devers – $1.0 billion total project cost; 2019-20 in service date



Note: Total Project Costs are nominal direct expenditures, subject to CPUC and FERC cost recovery approval

SCE Growth Drivers Beyond 2017

Infrastructure Reliability Investment

- Sustained level of infrastructure investment required until equilibrium replacement rates are achieved - includes underground cable, poles, switches, and transformers[1]

Grid Readiness

- Accelerate automation and control technology at optimal locations to manage two-way power flows with more dynamic voltage control
- Distribution Resource Plan required under AB 327 to identify optimal locations, additional spending, and barriers to deploying distributed energy resources – due to CPUC Q3 2015

Transmission

- California ISO 2013-2014 Transmission Plan[2] - approved Mesa Loop-in Project (system reliability post-SONGS and renewables integration) with target in-service date of December 31, 2020
- Two existing projects incorporated from prior Transmission Plans in service beyond 2017 include Coolwater-Lugo (2018) and West of Devers (2019-2020)

Energy Storage

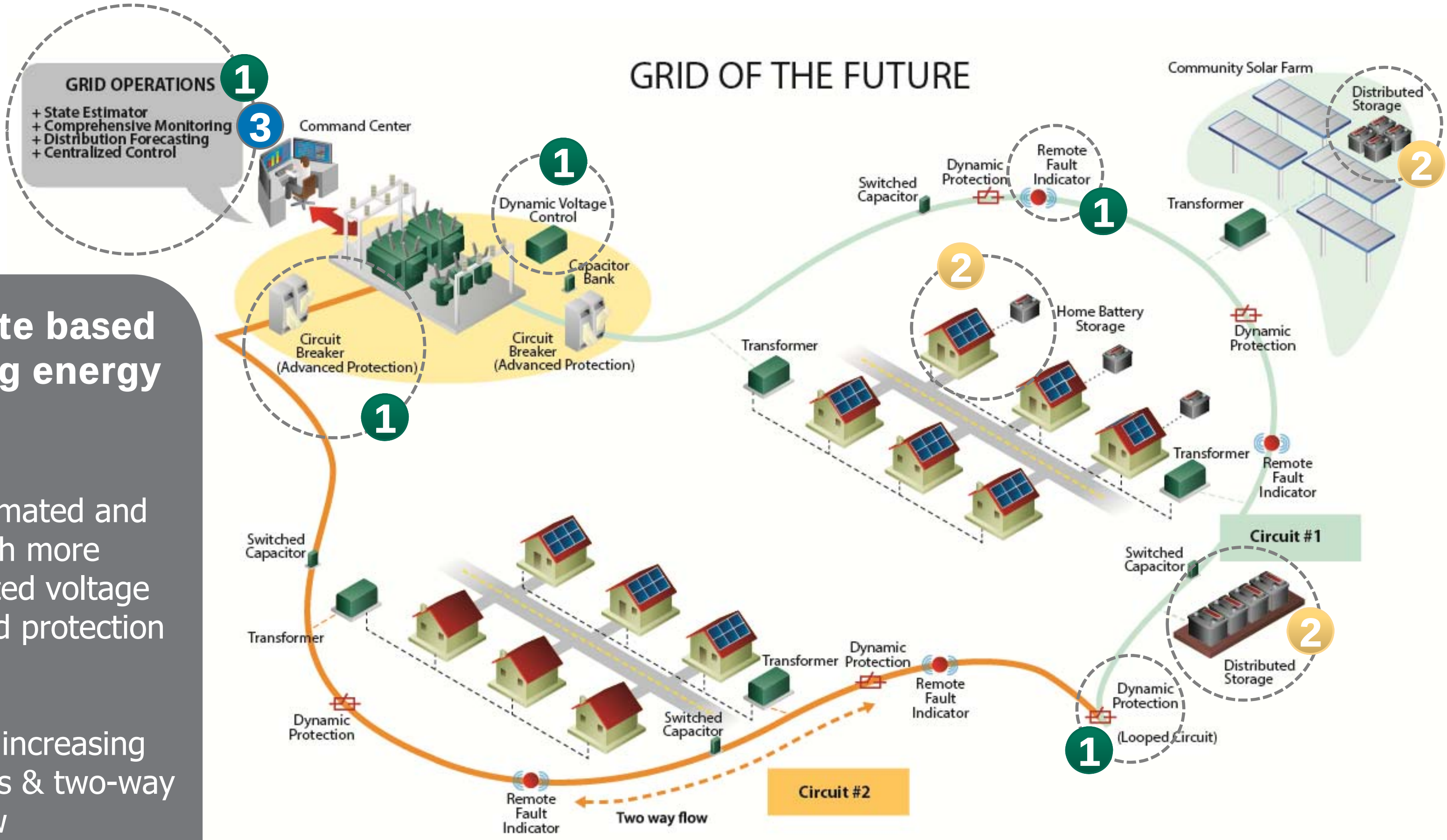
- 290 MW utility owned investment opportunity 2015-2024

Future Potential California Public Policy Requirements and Enabling Projects

- Transportation electrification
- Renewables mandates beyond 33%

1 Source: A.13-11-0032015 GRC – SCE-01 Policy testimony; equilibrium replacement rate defined as equipment population divided by mean time to failure for type of equipment
2 Approved by the California ISO Board of Governors March 20, 2014

New Technology Grid Impacts

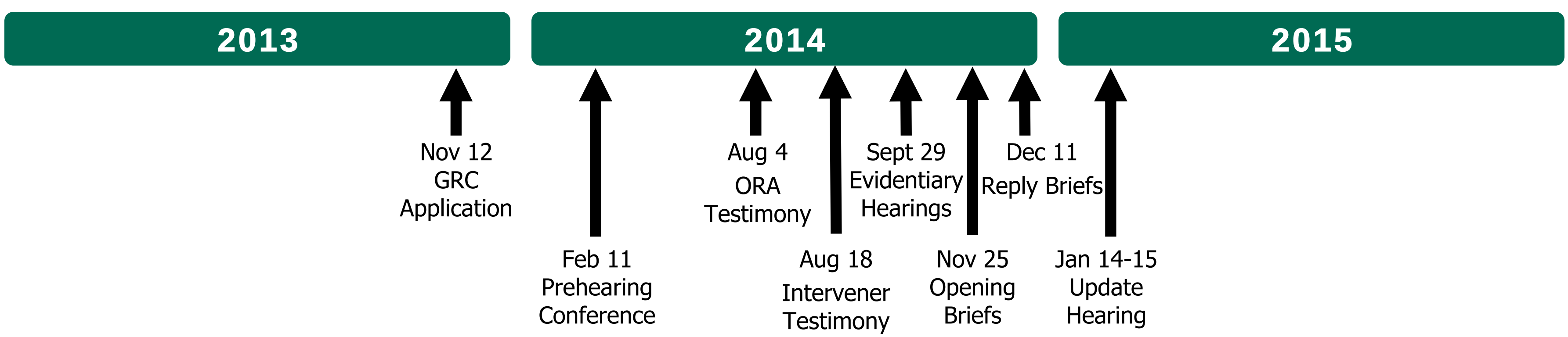


Future state based on evolving energy landscape

1. More automated and digital, with more sophisticated voltage control and protection schemes
2. Facilitates increasing renewables & two-way power flow
3. Cyber mitigation must be included

SCE 2015 CPUC General Rate Case

- November 2013, 2015 GRC Application A.13-11-003 filed
  - March 2014, Scoping Memo issued, schedule revised July 21st
  - Supplemental testimony, ordered by May 15th Assigned Commissions Ruling, on risk management and safety matters submitted July 3rd
- Request sets base revenue requirement for 2015 – 2017
  - Includes operating costs and CPUC jurisdictional capital
  - Excludes fuel and purchased power (and other utility cost-recovery activities), cost of capital, and FERC jurisdictional transmission
- 2015 revenue requirement request of $5.860 billion, after removing SONGS and Four Corners in April 2014
  - $227 million increase over presently authorized base rates (excluding SONGS)
  - Post test year requested increase of $321 million in 2016 and additional increase of $330 million in 2017
- Request consistent with SCE strategy to ramp up infrastructure investment consistent with capital plan while mitigating customer rate impacts through productivity and lower operating costs
- The current CPUC schedule does not specify a proposed decision timeframe but will likely be in 2015



SCE 2015 GRC – ORA Testimony

($ in millions)

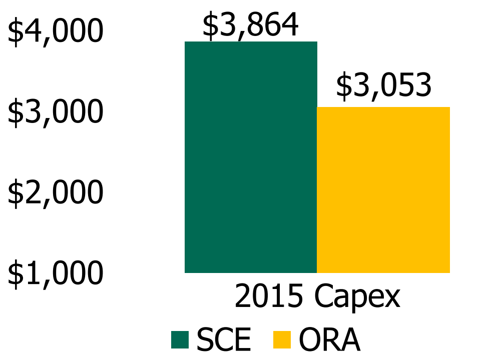
- August 4, Office of Ratepayer Advocate (ORA) submitted 2015 GRC testimony
  - Proposed $465 million 2015 test year decrease
  - Prior rate case testimony - $19 million 2012 test year increase; $7 million 2009 test year increase
  - Proposed $330 million O&M expense reduction driven by compensation and transmission and distribution

CPUC Revenue Requirement

	SCE	ORA
2015	$5,860	$5,168
2015 increase	$228 (4.0%)	$(465) (-8.3%)
2016 increase	$321 (5.5%)	$98 (1.9%)
2017 increase	$330 (5.3%)	$121 (2.3%)

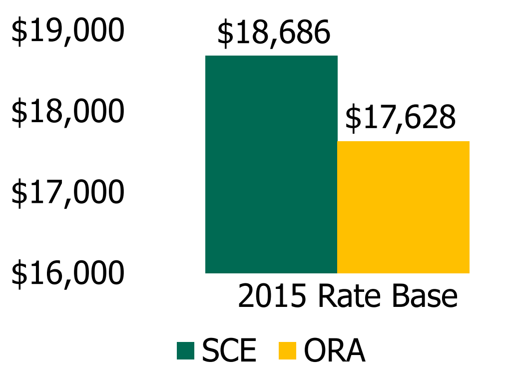
- 2015 – $692 million reduction
- Post test year ratemaking – CPI plus 0.5%

Total Company Capital Expenditures



- 2015 – $811 million reduction
- Mostly transmission and distribution reductions:
  - Sales forecast and load growth differences
  - Aged Pole program

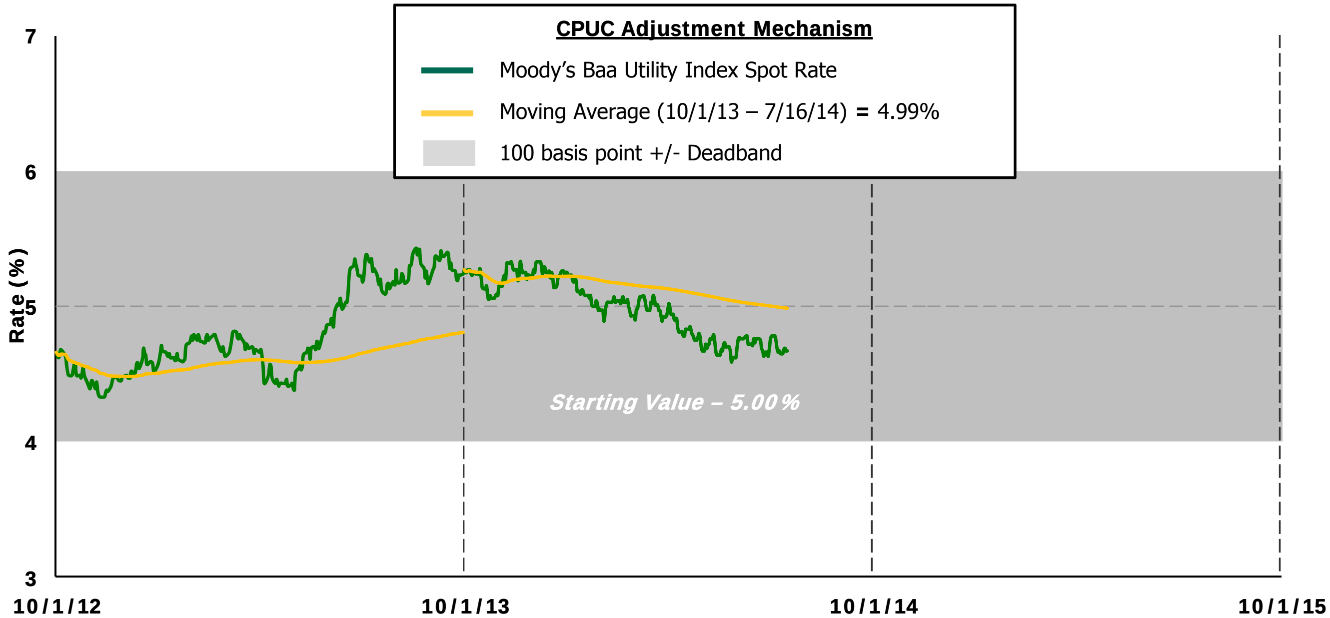
CPUC Rate Base



- 2015 – $1,058 million reduction
- $1.1 billion plant reduction from reduced capex
- $272 million lower depreciation – cost of removal rates and capital reductions

Note: Summary only. Please refer to August 4, 2014, ORA and other intervener testimony for more information.

CPUC and FERC Cost of Capital



- CPUC – 48% equity with 10.45% ROE and adjustment mechanism approved through 2015
  - Weighted average authorized cost of capital – 7.90%
  - ROE adjustment based on 12-month average of Moody's Baa utility bond rates, measured from Oct. 1 to Sept. 30
  - If index exceeds 100 bps deadband from starting index value, authorized ROE changes by half the difference
  - Starting index value based on trailing 12 months of Moody's Baa index as of September 30, 2012 – 5.00%
  - SCE will submit new application in April 2015 for Cost of Capital in 2016
- FERC – November 2013 settlement 10.45% ROE comprised of: 9.30% base + 50 bps CAISO participation + 65 bps weighted average for project incentives
  - Moratorium on filing ROE changes through June 30, 2015
  - FERC Formula recovery mechanism in effect through 2017

SCE Key Regulatory Events Calendar

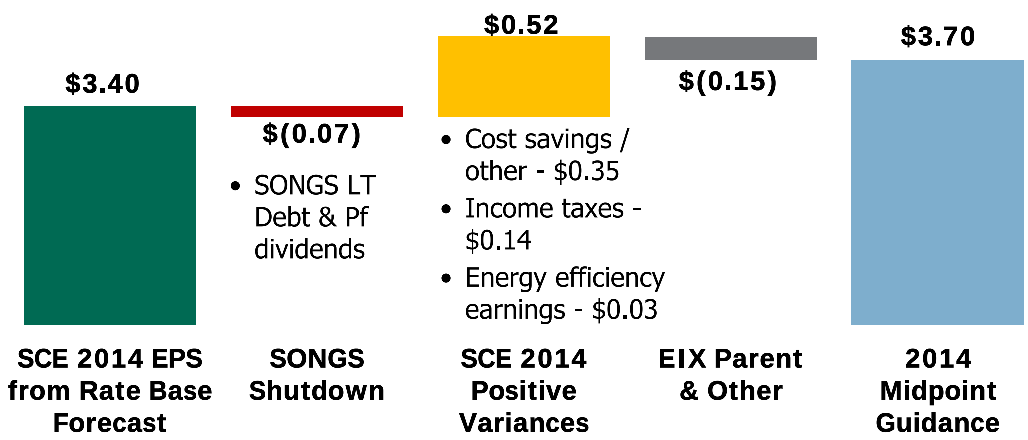
	2H 2014	1H 2015	2H 2015	2016
SONGS Settlement (I.12-10-013)	TBD – Proposed Decision			
2015 GRC (A.13-11-003)	July – Revised Scoping Memo Aug – ORA testimony Sept - Evidentiary Hearings	Jan – Update Hearing		
Rate Design OIR (R.12-06-013)	Sept – NEM Scoping Memo	Spring – Fixed charge and tiers proposed decision	Fall – NEM proposed decision	
Cost of Capital		April – Initial Filing		New Cost of Capital takes effect

Other proceedings next steps:

- **CAISO 2013-2014 Transmission Plan** – Board approval of Delaney-Colorado economic line in September 2014; project subject to FERC Order 1000 competitive bidding.
- **2012 Long Term Procurement Plan (LTPP) Track 1 Local Capacity Requirements (LCR)** – Total 1,400 to 1,800 MW preferred resources, gas-fired, energy storage to replace Once-Through-Cooling units, and Track 4 to replace SONGS authorizes 500 to 700 MW to be online by 2022, final selection on October 16, 2014.
- **Energy Storage OIR** – First procurement cycle December 2014. SCE targeting net 14 MW storage capacity, excluding 74 MW existing and LCR storage.

2014 Core and Basic Earnings Guidance

	2014 Earnings Guidance as of 4/29/14 Low	Mid	High
SCE		$3.85	
EIX Parent & Other		(0.15)	
EIX Core EPS [1]	**$3.60**	**$3.70**	**$3.80**
Non-core Items [2]		(0.36)	
EIX Basic EPS	**$3.24**	**$3.34**	**$3.44**



Key Assumptions:

- Midpoint rate base of $22.1 billion
- Approved capital structure – 48% equity, 10.45% CPUC & FERC ROE
- 325.8 million common shares outstanding (no change)
- No significant transmission project delays

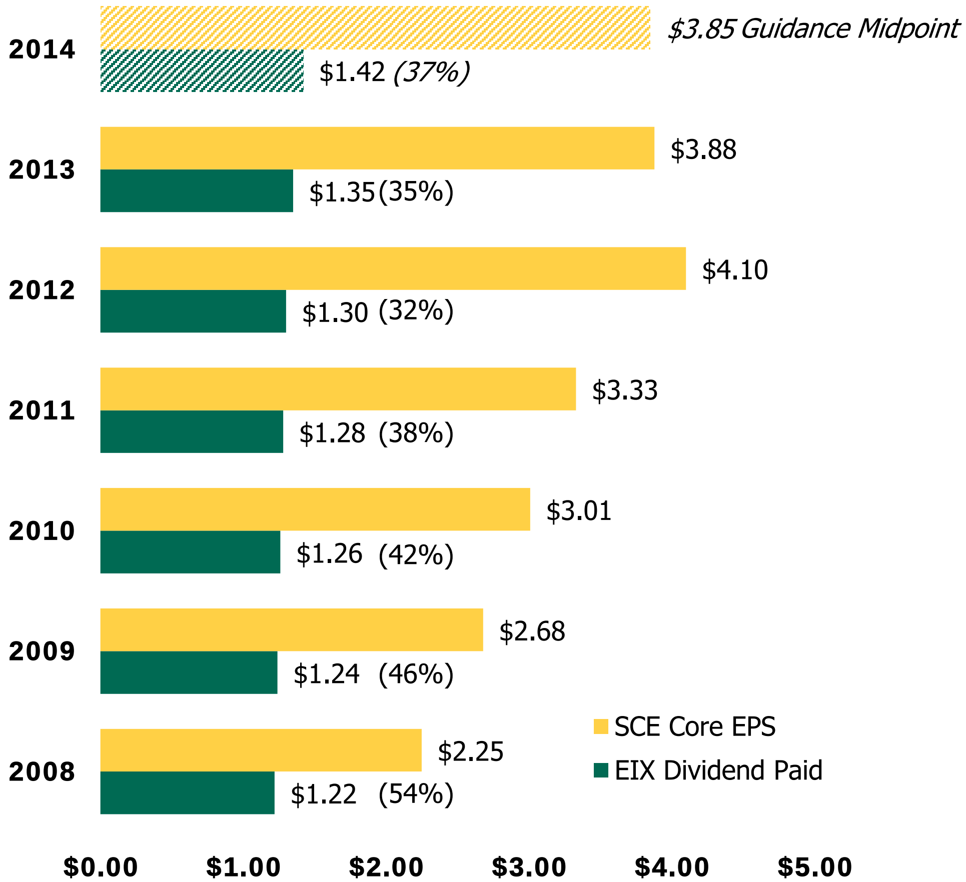
Other Assumptions:

- No change in tax policy
- O&M cost savings flow through to ratepayers in 2015 GRC
- Excludes $0.56 per share non-core item recorded in Q2 2014 but not in guidance
- Excludes $0.23 per share core items (uncertain tax position and other tax benefits, additional FERC revenue and FERC energy settlements) included in YTD 2014 results but not in guidance

Year to date earnings are trending above the high end of the guidance range and guidance may be adjusted when third quarter earnings are reported

1 See Use of Non-GAAP Financial Measures in Appendix
2 Represents non-core items recorded for the three months ended March 31, 2014

EIX Dividend Growth



2008 – 2013 CAGR

SCE Core EPS	12%
EIX Dividend	2%

- EIX targets paying out 45 – 55% of SCE earnings
- Dividend growth rate slowed to help fund large utility capital program, which is plateauing
- EIX plans to return to target dividend range over time

In December, EIX increased its dividend for the 10th consecutive year to an annual rate of $1.42 per share for 2014

Note: See Use of Non-GAAP Financial Measures in Appendix

Creating Shareholder Value

	Resolve Uncertainties	Create Sustainable Earnings and Dividend Growth	Position for Transformative Sector Change
What We've Done	• SCE 2013 cost of capital • SCE 2012 FERC formula rate settlement • EME restructuring • SONGS OII settlement reached	• 10% 5-year SCE rate base CAGR (2008 – 2013) • 12% Core SCE EPS growth (2008 – 2013) • 10 consecutive years of EIX dividend increases	• Acquired SoCore Energy (commercial solar) • Minority investments (energy efficiency, residential solar markets, transportation electrification)
What Remains	• SONGS OII settlement approval • SONGS third-party cost recovery • Monetize EME tax benefits	• SCE 2015 GRC • Execute wires-focused investment program • 7 – 9% projected rate base growth (2014 – 2017) • Optimize cost structure through operational excellence • Return to target dividend range over time	• Rate reform – AB 327 implementation • Evaluate new power sector business opportunities

Note: See use of Non-GAAP Financial Measures in Appendix

EIX is Responding to Industry Change

Long-Term Industry Trends

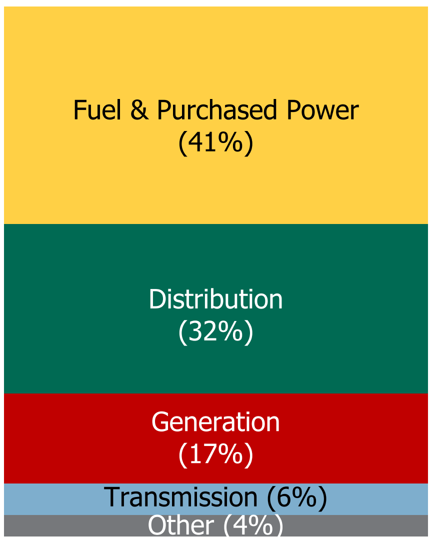
- Public policy prioritizing environmental sustainability
- Innovation facilitating conservation and self-generation
- Regulation supporting new forms of competition
- Flattening domestic demand for electricity
- Grid of the future will be more complex and sophisticated to support increasing use of distributed resources and transportation electrification

Strategy

- SCE Strategy
  - Invest in, build, and operate the next generation electric grid
  - Operational and service excellence
  - Enable California public policies
- EIX Competitive Strategy – small, targeted investments in emerging technologies and markets to follow changes in the industry and better exploit opportunities as they arise
  - Commercial and industrial distributed generation
  - Energy optimization
  - Energy efficiency and software
  - Residential solar industry financial services and software
  - Electric transportation

Appendix

SCE 2014 Bundled Revenue Requirement



	2014 Bundled Revenue Requirement $millions	2014 Bundled Revenue Requirement ¢/kWh
Fuel & Purchased Power – includes CDWR Bond Charge	5,071	6.9
Distribution – poles, wires, substations, service centers; Edison SmartConnect®	3,867	5.3
Generation – utility owned generation investment and O&M	2,048	2.8
Transmission – greater than 220kV	735	1.0
Other – CPUC and legislative public purpose programs, system reliability investments, nuclear decommissioning	539	0.7

Total Bundled Revenue Requirement ($millions)	**$12,260**
÷ Bundled kWh (millions)	73,249
= Bundled Systemwide Average Rate (¢/kWh)	**16.7¢**

Approximately 60% of SCE's revenue requirement consists of utility earnings activities: distribution, generation, and transmission

Note: Rates in effect as of July 7, 2014, based on forecast. Represents bundled service which excludes Direct Access customers that do not receive generation services.

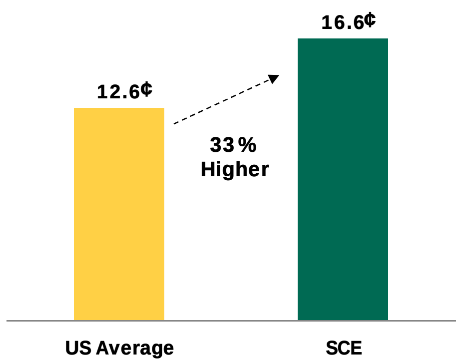
SCE Customer Demand Trends

Kilowatt-Hour Sales (millions of kWh)	2013	2012	2011	2010	2009
Residential	29,889	30,563	29,631	29,034	30,078
Commercial	40,649	40,541	39,622	39,318	40,076
Industrial	8,472	8,504	8,490	8,507	8,522
Public authorities	5,012	5,196	5,206	5,336	5,686
Agricultural and other	1,885	1,676	1,318	1,353	1,499
Subtotal	*85,907*	*86,480*	*84,267*	*83,548*	*85,861*
Resale	1,490	1,735	3,071	4,103	5,869
Total Kilowatt-Hour Sales	**87,397**	**88,215**	**87,338**	**87,651**	**91,730**
Customers					
Residential	4,344,429	4,321,171	4,301,969	4,285,803	4,262,966
Commercial	554,592	549,855	546,936	543,016	539,270
Industrial	10,584	10,922	11,370	11,708	12,244
Public authorities	46,323	46,493	46,684	46,718	46,902
Agricultural	21,679	21,917	22,086	22,321	22,315
Railroads and railways	99	83	82	73	67
Interdepartmental	23	24	22	23	23
Total Number of Customers	**4,977,729**	**4,950,465**	**4,929,149**	**4,909,662**	**4,883,787**
Number of New Connections	**27,370**	**22,866**	**19,829**	**25,566**	**32,145**
Area Peak Demand (MW)	**22,534**	**21,981**	**22,374**	**22,771**	**22,112**

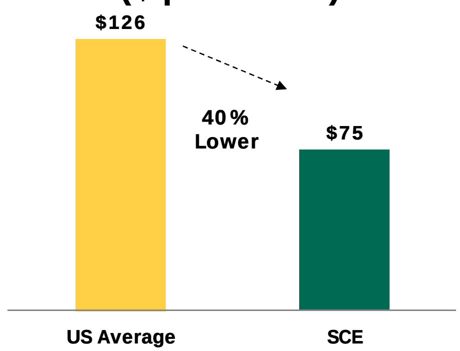
Note: See Edison International Financial and Statistical Reports for further information

SCE Rates and Bills Comparison

2014 Average Residential Rates (¢/kWh)



2014 Average Residential Bills ($ per Month)



Key Factors

- SCE's residential rates are above national average due, in part, to a cleaner fuel mix – cost for renewables are higher than high carbon sources
- Average monthly residential bills are lower than national average – higher rate levels offset by lower usage
  - 55% lower SCE residential customer usage than national average, from mild climate and higher energy efficiency building standards
- Public policy mandates (33% RPS, AB32 GHG, Once-through Cooling) and electric system requirements will drive rates and bills higher

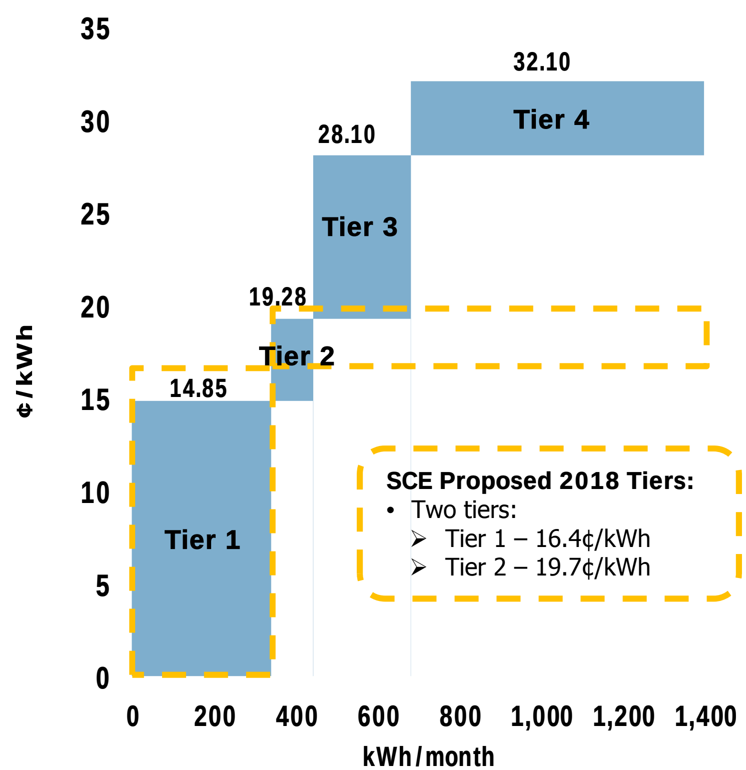
SCE's average residential rates are above national average, but residential bills are below national average due to lower energy usage

Source: EIA's Form 826 Data Monthly Electric Utility Sales and Revenue Data for the Data 12 Months Ending April 2014

Residential Rate Design OIR

- June 2012, CPUC opened Order Instituting Rulemaking (OIR) R.12-06-013:
  - ➢ Comprehensive review of residential rate structure
  - ➢ Transition to Time of Use (TOU) rates
  - ➢ AB327 rate design
- Phase 2 (Summer 2014): simple tiered rate adjustments
  - ➢ Settlement approved in June; rates implemented in July – 12% increase to Tier 1 rate, 17% increase to Tier 2 rate
- Phase 1 (2015 – 2018): longer-term rates
  - ➢ 2 tiers (2017); TOU rates (2018)
  - ➢ Fixed charge or minimum bill (2015)
  - ➢ Proposed Decision expected March 2015
- Net Energy Metering: successor tariff Q4 2015
  - ➢ 20-year NEM grandfathering for existing customers and new installations up to 5% cap (2,240 MW for SCE)
  - ➢ NEM grandfathered customers still subject to new tier structure

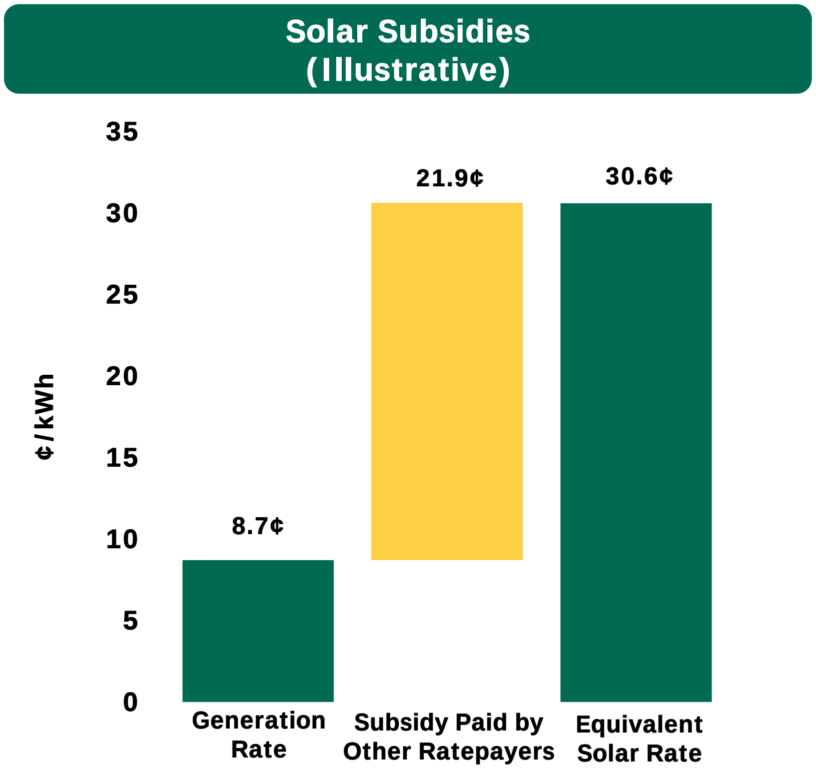
OIR Phase 2 Settlement Summary



Fixed Monthly Charge

Current:	$0.94/month
SCE Proposed:	$10/month

SCE Residential Net Metering Rate Structure



- Residential solar customer generation offsets total retail rate
- Average retail rate of 30.6¢/kWh vs. actual generation cost of 8.7¢/kWh
- Resulting 21.9¢/kWh is a subsidy funded by all other non-solar customers in Tiers 3 and 4

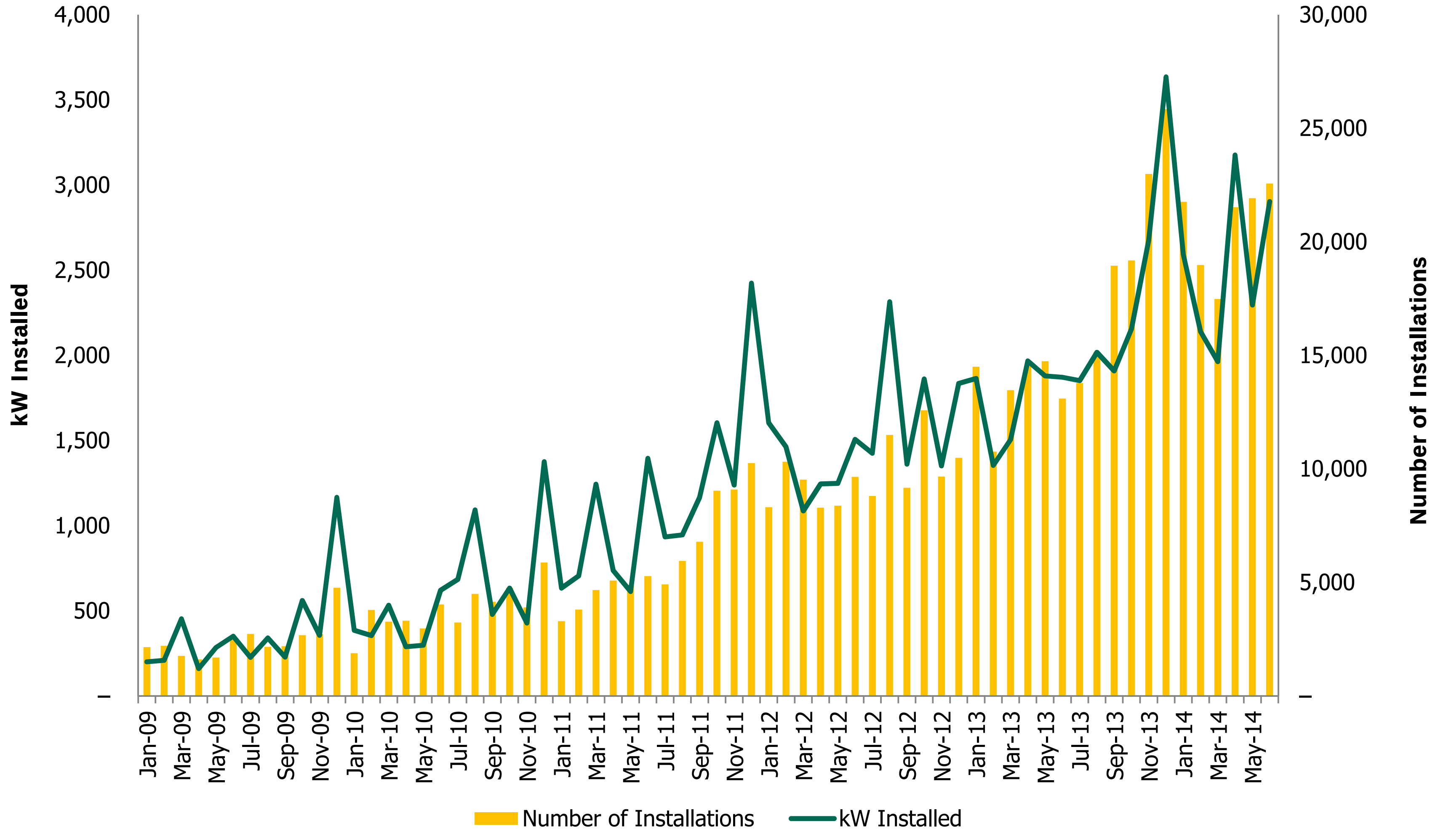
SCE 2013 Net Energy Metering Statistics:

- 76,400 combined residential and non-residential customers – 697 MW installed
  - 99.5% solar
  - 73,300 residential – 361 MW
  - 3,100 non-residential – 336 MW
- Approximately 1,000,000 mWh / year generated, or 1% of total sales

Current rate design results in residential solar customers receiving a subsidy funded by all other non-solar customers in higher tiers

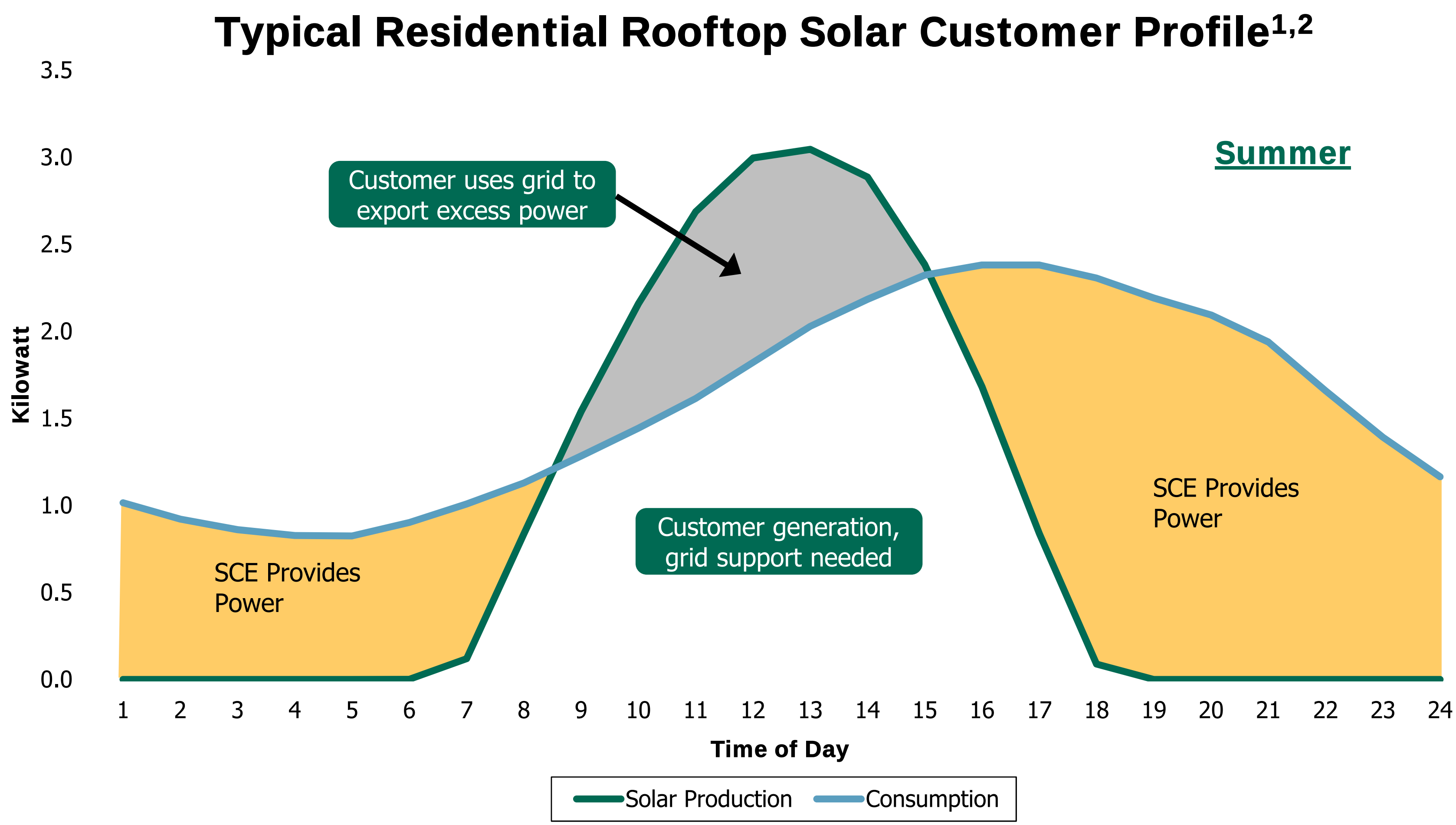
Note: Based on average home usage of 1,150 kWh/month, a 4-tier rate structure, and a 4.8kW solar system with a 18% capacity factor that generates 631 kWh per month

Solar Installations in SCE Service Territory



Note: NEM solar installations in SCE service territory include projects with solar PV only less than 1 MW

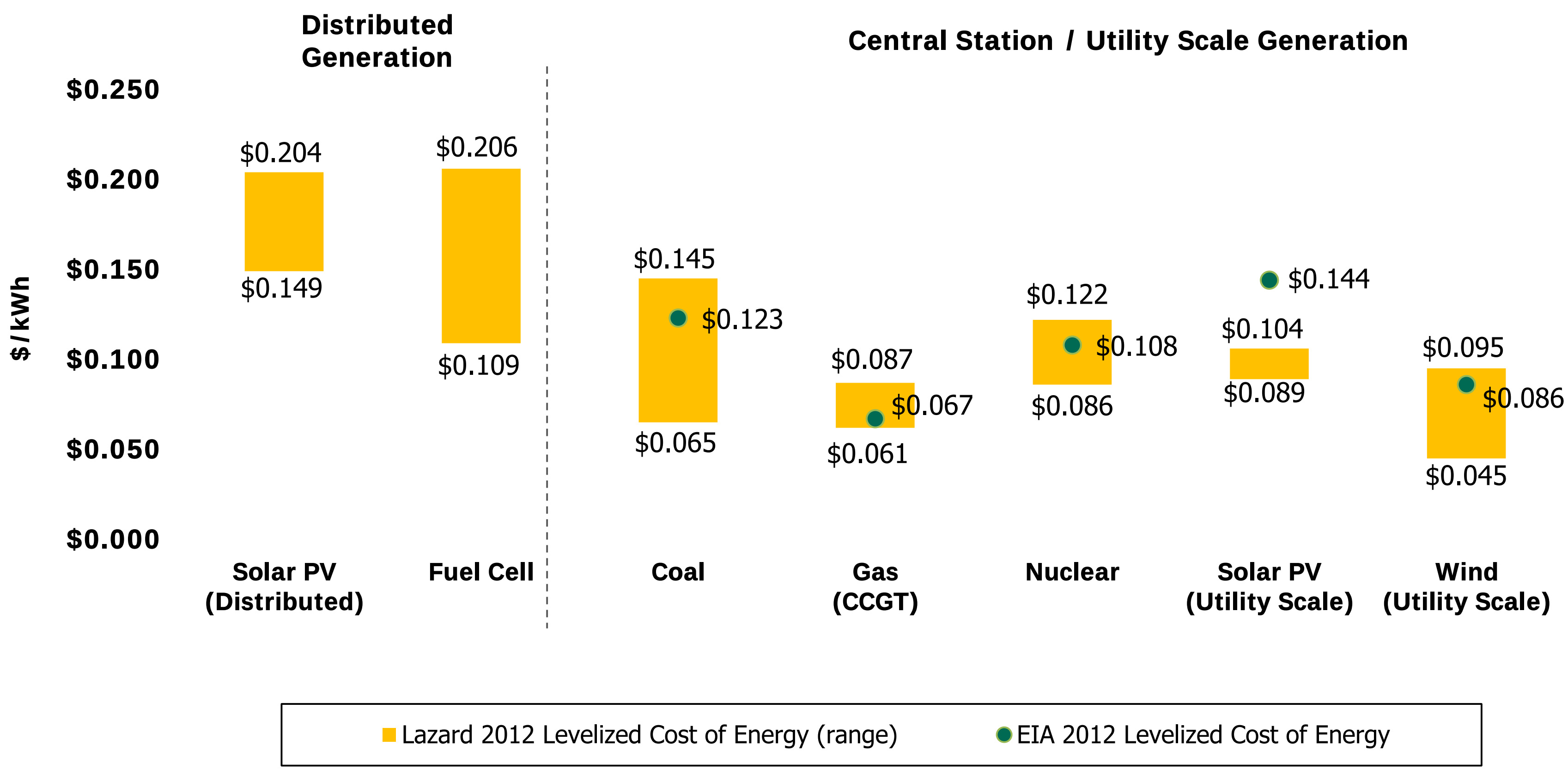
Rooftop Solar – Grid Interaction



Solar customers benefit from the flexibility provided by the SCE grid

1 Solar production shape based on a 4.8 kW system expected summer performance (source: https://sam.nrel.gov/). Sizing to eliminate Tier 3 and 4 usage.
2 Residential consumption shape based on summer average for a high user (1,150 kWh/month) (source: SCE load research)

All Generation Cost Trends, Unsubsidized



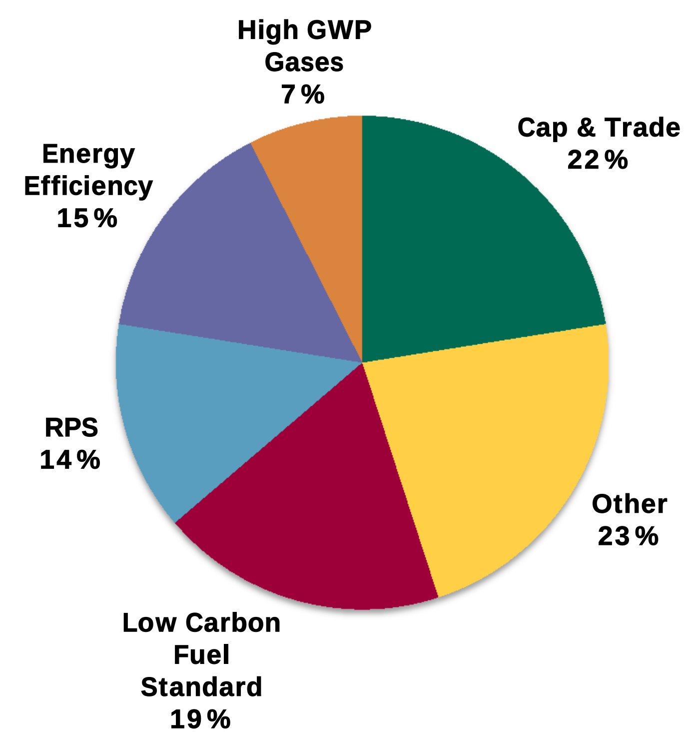
Levelized cost of energy for distributed generation resources continues to move toward equilibrium with other generation sources

Sources: Lazard Levelized Cost of Energy Version 7.0 August 2013; EIA Levelized Cost of Energy Analysis 2013

California Climate Change Policy

- Assembly Bill 32 (2006) – reduces State greenhouse gas (GHG) emissions to 1990 levels by 2020 (~16% reduction)
- Cap and trade program basics:
  - ➢ State-wide cap in 2013 – decreases over time
  - ➢ Compliance met through allowances, offsets, or emissions reductions
  - ➢ Excess allowances sold, or "banked" for future use
  - ➢ January 2014 – merger with Quebec cap and trade program
- SCE received 32.3 million 2013 allowances vs. 10.4 million metric tons 2012 GHG emissions
- Allowances sold into quarterly auction and bought back for compliance
  - ➢ SB 1018 (2012) – auction revenues used for rate relief for residential (~93%), small business, and large industrial customers

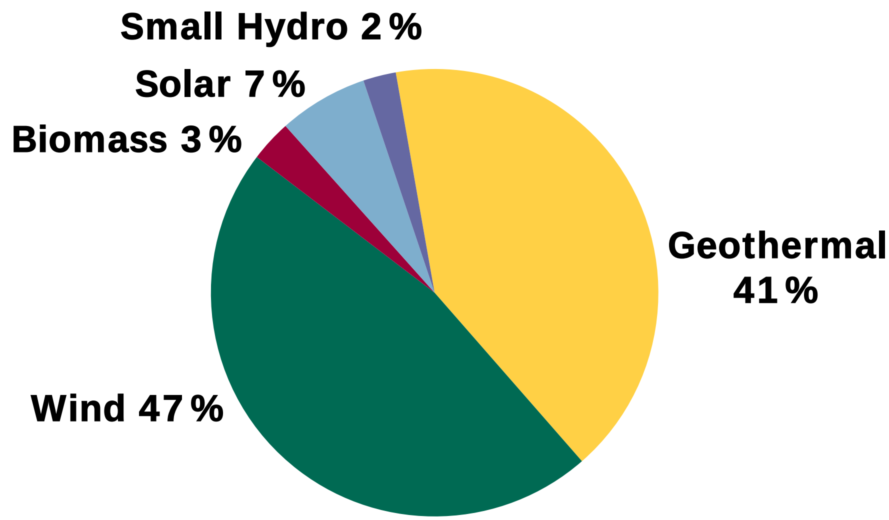
AB32 Emissions Reduction Programs



California Renewables Policy

- On April 12, 2011, Governor Brown signed SB X 1 2, which codifies a 33% Renewables Portfolio Standard (RPS) for California by 2020
  - Allows use of Renewable Energy Credits (RECs) for up to 25% of target with decreasing percentages over time
  - Applies similar RPS rules to all electricity providers (investor- and publicly-owned utilities, as well as Electric Service Providers)
- In order to meet the 33% RPS requirement by 2020, SCE will increase its renewable purchases by 10 billion kWh, or 60%

Actual 2013 Renewable Resources:
21.6% of SCE's portfolio

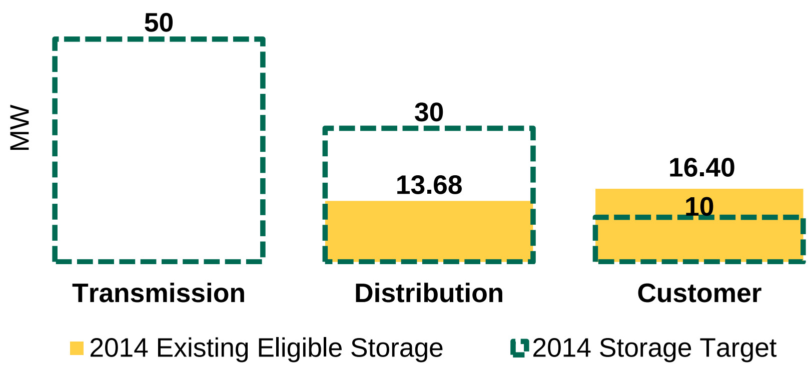


While SCE is on track to meet the 33% renewables target by 2020, the requirement will put upward pressure on customer rates

Energy Storage

- AB2514 directed CPUC to establish procurement targets and policies for storage
- CPUC final decision in Energy Storage OIR (R.10-12-007)
  - 1,325 MW target for IOUs by 2024 (580 MW SCE share)
  - Three types: transmission (53%), distribution (32%), customer-sited (15%)
  - Utility ownership limited to 50% of total target (290 MW SCE share)
  - First standalone procurement cycle in December 2014
    - Existing storage and prior RFO storage expected to count for ~74MW of SCE's 90 MW target
  - Broad range of technologies as defined in AB2514, excluding large hydro (>50 MW)

SCE 2014 Existing Storage



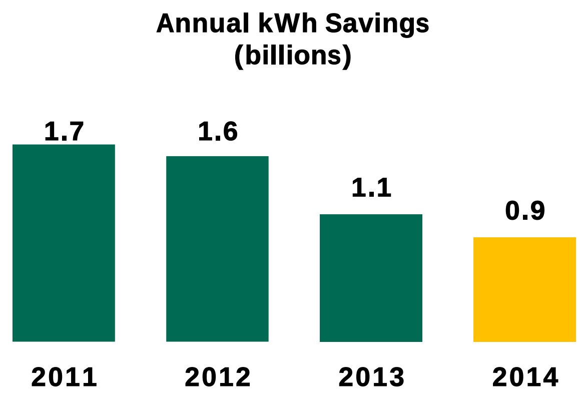
- Tehachapi Storage Project
- Irvine Smart Grid Demonstration Projects
- Large Energy Storage Test Apparatus
- Discovery Science Center
- Catalina Island Battery System
- Vehicle-to-Grid Program – LA Air Force Base
- Self-Generation Incentive Program
- Permanent Load Shifting Program

SCE's energy storage investment opportunities will focus on distribution grid projects and will be integrated into future capital expenditure requests

SCE Energy Efficiency Programs

Energy efficiency programs updated for 2013 – 2014

- SCE is a national leader
  - 2012 energy savings = 1.8% of retail sales[1]
- 2014 budget of $352 million[2]
- Target 0.9 billion kWh average annual savings for 2013-14 cycle[3] – Reduced goals reflect CPUC-identified market potential for energy efficiency



Energy efficiency earnings incentive mechanism modified

- New earnings mechanism for 2011, 2012 (payable in 2013, 2014) – 5% management fee + up to 1% performance bonus
- December 2013, $13.5 million awarded for 2011 program year – additional $5 million pending results of 2014 energy efficiency programs audit
- SCE to file earnings claim for 2012 and part of 2013 program activity this year – actual payment, if any, subject to CPUC approval
- CPUC approved new incentive mechanism for 2013 and 2014 activities (payable in 2014 and beyond) comprised of performance rewards and management fees

Future Directions

- SCE is identifying opportunities, such as SCE's Preferred Resources Pilot, to leverage EE and other demand side resources to meet grid reliability needs.

1 Does not include resale sales. Energy savings subject to ex-post CPUC review.
2 Excludes income qualified energy efficiency and integrated demand-side management program funding authorizations for 2013
3 Based on CPUC goals established for SCE. Market potential changes in response to program funding levels, customer participation assumptions, market influences and the implementation of new building codes and minimum appliance efficiency standards

Second Quarter Earnings Summary

	Q2 2014	Q2 2013	Variance
Core EPS[1]			
SCE	$1.11	$0.84	$0.27
EIX Parent & Other	(0.03)	(0.05)	0.02
Core EPS[1]	**$1.08**	**$0.79**	**$0.29**
Non-Core Items			
SCE	$–	$(1.12)	$1.12
EIX Parent & Other	–	–	–
Discontinued Operations	0.56	0.04	0.52
Total Non-Core	**$0.56**	**$(1.08)**	**$1.64**
Basic EPS	**$1.64**	**$(0.29)**	**$1.93**
Diluted EPS	**$1.63**	**$(0.29)**	**$1.92**

SCE Key Core Earnings Drivers

Higher revenue		$0.17
SONGS impact		0.03
Higher O&M[2]		(0.02)
Higher depreciation		(0.05)
Higher net financing costs		(0.02)
Income taxes and other		0.16
- Changes in uncertain tax positions	0.09	
- Other tax benefits	0.04	
- Generator settlements	0.03	
Total		$0.27

EIX Key Core Earnings Drivers

Higher tax benefits	$0.03
Costs of new businesses	(0.01)
Total	$0.02

1 See Earnings Non-GAAP Reconciliations and Use of Non-GAAP Financial Measures in Appendix
2 Includes non-SONGS severance of $0.01 and $0.02 for the three months ended June 30 of 2014 and 2013, respectively

Year-to-Date Earnings Summary

	YTD 2014	YTD 2013	Variance
Core EPS[1]			
SCE	$2.04	$1.63	$0.41
EIX Parent & Other	(0.06)	(0.06)	0.00
Core EPS[1]	**$1.98**	**$1.57**	**$0.41**
Non-Core Items			
SCE	$(0.29)	$(1.12)	$0.83
EIX Parent & Other	–	0.02	(0.02)
Discontinued Operations	0.49	0.07	0.42
Total Non-Core	**$0.20**	**$(1.03)**	**$1.23**
Basic EPS	**$2.18**	**$0.54**	**$1.64**
Diluted EPS	**$2.17**	**$0.54**	**$1.63**

SCE Key Core Earnings Drivers

Higher revenue		$0.31
SONGS impact		0.02
Lower O&M[2]		0.05
Higher depreciation		(0.12)
Higher net financing costs		(0.05)
Income taxes and other		0.20
- Changes in uncertain tax positions	0.09	
- Other tax benefits	0.08	
- Generator settlements	0.03	
Total		$0.41

EIX Key Core Earnings Drivers

Higher tax benefits	$0.01
Costs of new businesses	(0.01)
Total	$0.00

1 See Earnings Non-GAAP Reconciliations and Use of Non-GAAP Financial Measures in Appendix
2 Includes non-SONGS severance of $0.01 and $0.05 for the six months ended June 30, 2014 and 2013, respectively

Earnings Non-GAAP Reconciliations

($ millions)

Reconciliation of EIX Core Earnings to EIX GAAP Earnings

Earnings Attributable to Edison International	Q2 2014	Q2 2013	YTD 2014	YTD 2013
Core Earnings				
SCE	$362	$274	$666	$530
EIX Parent & Other	(10)	(15)	(20)	(20)
Core Earnings	**$352**	**$259**	**$646**	**$510**
Non-Core Items				
SCE	$–	$(365)	$(96)	$(365)
EIX Parent & Other	–	–	–	7
Discontinued operations	184	12	162	24
Total Non-Core	*184*	*(353)*	*66*	*(334)*
Basic Earnings	**$536**	**$(94)**	**$712**	**$176**

Note: See Use of Non-GAAP Financial Measures in Appendix

SCE Core EPS Non-GAAP Reconciliations

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

Earnings Per Share Attributable to SCE	2008	2009	2010	2011	2012	2013	CAGR
Core EPS	**$2.25**	**$2.68**	**$3.01**	**$3.33**	**$4.10**	**$3.88**	**12%**
Non-Core Items							
Tax settlement	—	0.94	0.30	—	—	—	
Health care legislation	—	—	(0.12)	—	—	—	
Regulatory and tax items	(0.15)	0.14	—	—	0.71	—	
Asset impairment	—	—	—	—	—	(1.12)	
Total Non-Core Items	**(0.15)**	**1.08**	**0.18**	—	**0.71**	**(1.12)**	
Basic EPS	**$2.10**	**$3.76**	**$3.19**	**$3.33**	**$4.81**	**$2.76**	**6%**

Note: See Use of Non-GAAP Financial Measures in Appendix

SCE Results of Operations

($ millions)

- Utility earning activities – revenue authorized by CPUC and FERC to provide reasonable cost recovery and return on investment
- Utility cost-recovery activities – CPUC- and FERC-authorized balancing accounts to recover specific project or program costs, subject to reasonableness review or compliance with upfront standards

	2013			2012		
	Utility Earning Activities	Utility Cost-Recovery Activities	Total Consolidated	Utility Earning Activities	Utility Cost-Recovery Activities	Total Consolidated
Operating revenue	$6,602	$5,960	$12,562	$6,682	$5,169	$11,851
Fuel and purchased power	—	4,891	4,891	—	4,139	4,139
Operation and maintenance	2,348	1,068	3,416	2,518	1,026	3,544
Depreciation, decommissioning and amortization	1,622	—	1,622	1,562	—	1,562
Property and other taxes	307	—	307	296	(1)	295
Asset impairment and disallowances	575	—	575	32	—	32
Total operating expenses	4,852	5,959	10,811	4,408	5,164	9,572
Operating income	1,750	1	1,751	2,274	5	2,279
Interest income and other	48	—	48	94	—	94
Interest expense	(519)	(1)	(520)	(494)	(5)	(499)
Income before income taxes	1,279	—	1,279	1,874	—	1,874
Income tax expense	279	—	279	214	—	214
Net income	1,000	—	1,000	1,660	—	1,660
Preferred and preference stock requirements	100	—	100	91	—	91
Net income available for common stock	$900	$—	$900	$1,569	$—	$1,569
Core earnings			$1,265			$1,338
Non-core earnings			(365)			231
Total SCE GAAP earnings			$900			$1,569

Note: See Use of Non-GAAP Financial Measures in Appendix

SONGS Settlement – Summary

Term	Description
Steam Generators	• Steam Generator Replacement Project ("SGRP") removed from rates as of February 1, 2012, with book value balance disallowed. Revenues related to the SGRP collected after February 1, 2012, refunded to customers.
Power Costs	• Full recovery of replacement power costs
Regulatory Asset Recovery	• Non SGRP plant costs are recovered in rates over 10 years from February 1, 2012 • Weighted average return equal to authorized cost on debt and 50% of authorized cost on preferred; no return on equity. Results in current weighted average return of 2.62%. • Construction Work in Progress (CWIP) and materials and supplies are recovered with same return over same period • Nuclear Fuel amortized over same period; return at customary commercial paper rate • 5% of proceeds of any sales / dispositions of materials, supplies, and nuclear fuel accrue to shareholders, as well as 5% reduction in nuclear fuel commitments • Regulatory Asset can be removed from ratemaking capital structure, thus reducing equity requirement in excess of $300 million
Operations & Maintenance Costs	• Recorded O&M for 2013 recovered, including incremental inspection and repair costs • O&M recovery for 2012 limited to CPUC authorized amounts • Leaves $99 million incremental inspection and repair costs not recovered in rates (these costs were previously expensed)
Sharing of SCE Recovery Proceeds	• NEIL: 82.5% ratepayers / 17.5% Shareholders • MHI: Shareholders receive 85% of first $100 million; 2/3 of next $800 million; and 1/4 of amounts above $900 million • Litigation costs recovered before sharing starts

SONGS Settlement – Third-Party Recoveries

- SCE's share of recoveries from NEIL and MHI will be allocated between SCE and customers
- Litigation fees recovered prior to SCE / customer sharing

SCE Share

NEIL	All →	17.5%
MHI		
• First	$100 million →	85%
• Next	$800 million →	66.67%
• Above	$900 million →	25%

Non-Core Earnings

Customer Share

NEIL	All →	82.5%
MHI		
• First	$100 million →	15%
• Next	$800 million →	33.33%
• Above	$900 million →	75%

NEIL

- Credit to ERRA

MHI

- First $282 million – credit to General Rate Case Base Revenue Requirement Balancing Account (BRRBA)
- Above $282 million – reduce SONGS regulatory asset
- Credit to BRRBA after full SONGS regulatory asset recovered

SONGS Settlement – Accounting

- Q2 2013, SCE recorded $575 million pre-tax and $365 million after-tax impairment based on management's judgment of the recoverability of SONGS investment
  - ➢ Developed based on a range of possible outcomes
  - ➢ Each quarter, management must assess recoverability
- Q1 2014, SCE increased its total pre-tax impairment by $231 million to a total of $806 million (after-tax increase of $96 million to a total of $461 million) based on terms of Settlement Primary drivers of impairment charge:
  - ➢ Disallowance of SGRP investment – $542 million as of May 31, 2013
  - ➢ Refund of revenues related to SGRP previously recognized – $159 million
  - ➢ Implementation of other terms of the Settlement Agreement, including refund of authorized return in excess of the return allowed for non-SGRP investments
  - ➢ Refund of revenues to customers from flow-through tax benefits – increases effective tax rate
- If approved, the settlement would result in a core earnings benefit of approximately $0.03 per share in 2014 and $0.04 per share annually, declining over 10 years
- SCE has not recorded a receivable for potential recoveries from either MHI or NEIL

SCE recorded an additional pre-tax impairment of $231 million ($96 million after-tax, or $0.29 per share) in Q1 2014

SONGS Settlement – Regulatory Asset

($ millions)

Category	December 31, 2013[1]	June 30, 2014	Authorized Return
Base Plant	$2,166	$488	2.62%
SGRP		-	n/a
CWIP[2]		403	2.62%
Materials and Supplies		78	2.62%
Nuclear Fuel		407	Commercial Paper Rate
Asset Impairment	(575)	(5)	n/a
Regulatory Asset	**$1,591**	**$1,371**	

Estimated Revenue Refund

Authorized revenue in excess of recorded	(266)	(483)

As of June 30, 2014, SONGS regulatory assets under the Settlement Agreement are $1.4 billion, with recovery expected through January 31, 2022

1 December 31, 2013, balance of $2,166 million comprised of $2,096 million net investment at May 31, 2013, plus $70 million of costs recorded thereafter. Individual components not disclosed.

2 CWIP includes both completed and cancelled CWIP as defined by the Settlement Agreement

SONGS Third-Party Recovery – MHI

Warranty Summary

- 20-year warranty:
  - Repair or replace defective items
  - Specified damages for certain repairs
  - $138 million liability limit and exclusion for consequential damages (e.g. replacement power)
  - Limits subject to applicable exceptions in the contract and under law
- 7 invoices submitted totaling $149 million for repair costs through April 30, 2013
  - First invoice of $45 million ($36 million SCE share) paid, subject to audit, reservation of rights regarding documentation

Request for Arbitration

- October 2013, Request for Arbitration filed with the International Chamber of Commerce per MHI contract
- Claims for damages consistent with July 2013 Notice of Dispute that was unsuccessfully resolved with MHI
- Exceptions to damage limitations are argued to apply:
  - Direct Damages – $138 million warranty cap does not apply due to, among other things, gross negligence
  - Consequential Damages – contract waiver does not apply due to, among other things, "failure of essential purpose"
- MHI responded in December 2013 countering SCE's claims and asserting $41 million in counterclaims

SCE's position is that the steam generator tube leak and resulting damages represent a total and fundamental failure of performance by MHI

SONGS Third-Party Recovery – NEIL Insurance

- Accidental property damage and accidental outage insurance through Nuclear Electric Insurance Limited ("NEIL")
  - Accidental Property Damage Policies – $2.5 million deductible; $2.75 billion liability limit
  - Accidental Outage Policy – weekly indemnity up to $3.5 million per 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
- Accidental outage policy benefits are reduced to:
  - 80% of weekly indemnity after 52 weeks; and
  - 10% of weekly indemnity after early retirement announcement
- Separate proofs of loss have been filed for Unit 2 and Unit 3 under NEIL accidental outage policy totaling $414 million ($325 million SCE share) for amounts through February 22, 2014
  - SCE is continuing to make weekly indemnity claims post-shutdown decision at 10% value per the terms of the policy
  - SCE has not submitted a proof of loss under the accidental property damage policies – SCE has received an extension to file such a claim to December 31, 2014
- NEIL may make a coverage determination by end of Q3 2014, but it may take longer

SONGS – Units 2 and 3 Decommissioning

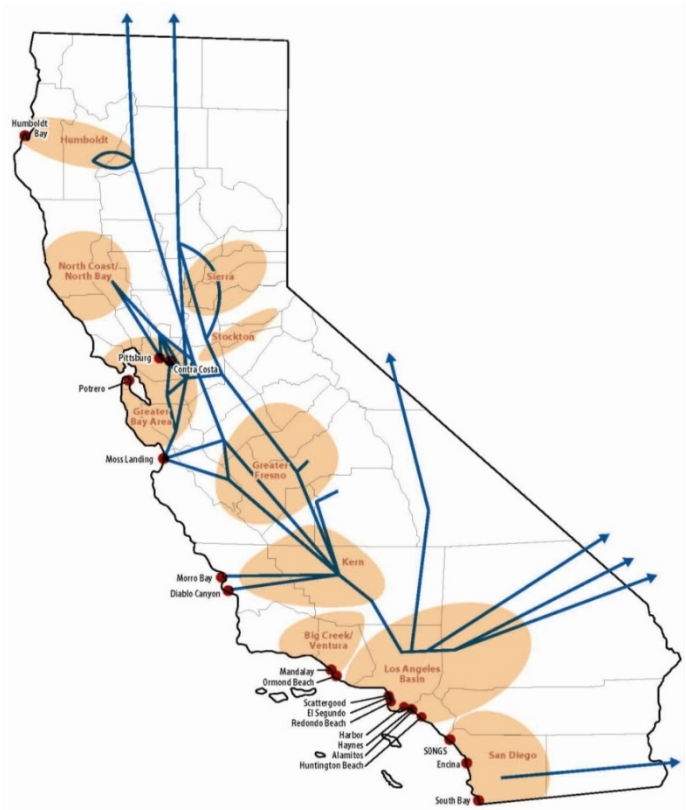
Decommissioning Trusts

- Decommissioning Trust contributions recovered in rates approved by CPUC in triennial proceeding
- Updated site-specific decommissioning cost study estimate (2014 dollars, all owners): $4.4 billion, or $106 million less than previous estimate
    - SCE share of decommissioning costs is $3.3 billion (2014 dollars), or $2.9 billion (after cost escalation and discounting)
    - SCE nuclear decommissioning trust funds total $3.1 billion after estimated taxes, or 104% funded
- No additional nuclear decommissioning trust fund contributions are needed at this time

Decommissioning Process

- June 2013, Certification of Permanent Cessation of Power Operations submitted to NRC
- All initial decommissioning activity phase plans and cost estimates will be provided by end of 2014
- Decommissioning involves three related activities: radiological decommissioning, non-radiological decommissioning and management of spent nuclear fuel
- Access to the decommissioning trusts requires an order from the CPUC. SCE's advice letter requesting interim access is pending before the commission.

SCE System Reliability



CA Once Through Cooling Policy – Legend

Coastal Power Plants

Local Reliability Areas (generalized)

California Transmission System (partial, generalized)

- Short-term SONGS closure solutions
  - Transmission – 220 kV Barre-Ellis reconfiguration
  - Voltage support – Huntington Beach 3 and 4 synchronous condensers
  - Substations – Santiago, Viejo, Johanna capacitor bank upgrades
  - Generation – El Segundo repower (550 MW), Sentinel (728 MW), Walnut Creek (480 MW)
  - Conservation – EE, demand response, Flex Alerts
- Long-term issues
  - Once-through cooling – approximately 6,000 MW affected in SCE territory
  - Air quality and emissions – limitations on permits, cap and trade market
  - Distributed generation and renewables – integration, flexibility and net load

EME Bankruptcy Settlement Implementation

- April 2014, amended Plan of Reorganization completed
- EME emerged from bankruptcy and remains subsidiary of EIX Consolidated for tax purposes
- Reorganization Trust established to receive tax benefit payments from EIX

Cash Impact

- Based on the preliminary estimate:
  - EIX expects net benefits of approximately $232 million
  - EIX expects to utilize approximately $1.2 billion of EME tax benefits – 50% to Reorganization Trust
  - EIX would make an estimated $634 million in total payments through 2016 (including interest):
    - $225 million paid April 1, 2014
    - $199 million on September 30, 2015
    - $210 million on September 30, 2016
- Deferred payment amounts to be finalized by the end of 2014

Accounting Treatment

- Approximately $48 million of net benefits recorded as non-core income through March 31, 2014
- Balance of net benefits of $184 million was recorded as non-core income in Q2 2014

Use of Non-GAAP Financial Measures

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

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

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