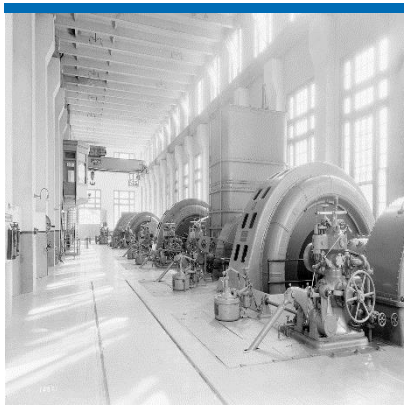
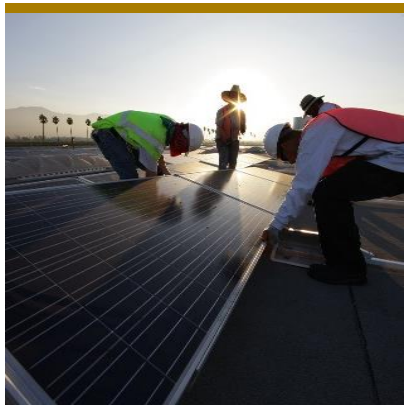
EDISON INTERNATIONAL®

Business Update
July 2015


Forward-Looking Statements

Statements contained in this presentation about future performance, including, without limitation, operating results, asset and rate base growth, capital expenditures, financial outlook, 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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EIX Strategy Should Produce Superior Value

Sustainable Earnings and Dividend Growth

Rate Base and Core Earnings Growth

- 7 – 9% average annual rate base growth through 2017

Constructive Regulatory Structure

- Decoupling
- Balancing accounts
- Forward-looking ratemaking

Sustainable Dividend Growth

- Target payout ratio: 45-55% of SCE core earnings
- Returning to target payout ratio in steps over time produces above industry-average dividend growth

Positioned for Transformative Change

SCE Focus on Lower-Risk Energy Delivery

- Wires assets represent over 90% of utility plant as of December 31, 2014[1]

SCE Growth Drivers Beyond 2017

- Public safety and reliability
- Distribution Resources Plan
- Electric vehicle charging and storage
- State environmental policy
- Transmission

Edison Energy Competitive Strategy

- Integrate emerging technologies and business models to expand electrification and serve commercial and industrial customers

1. Includes assets classified as transmission, distribution and general plant

SCE Highlights

One of the nation's largest electric utilities

- Nearly 14 million residents in service territory
- 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
- 3,100 MW owned generation

Above average annual rate base growth driven by

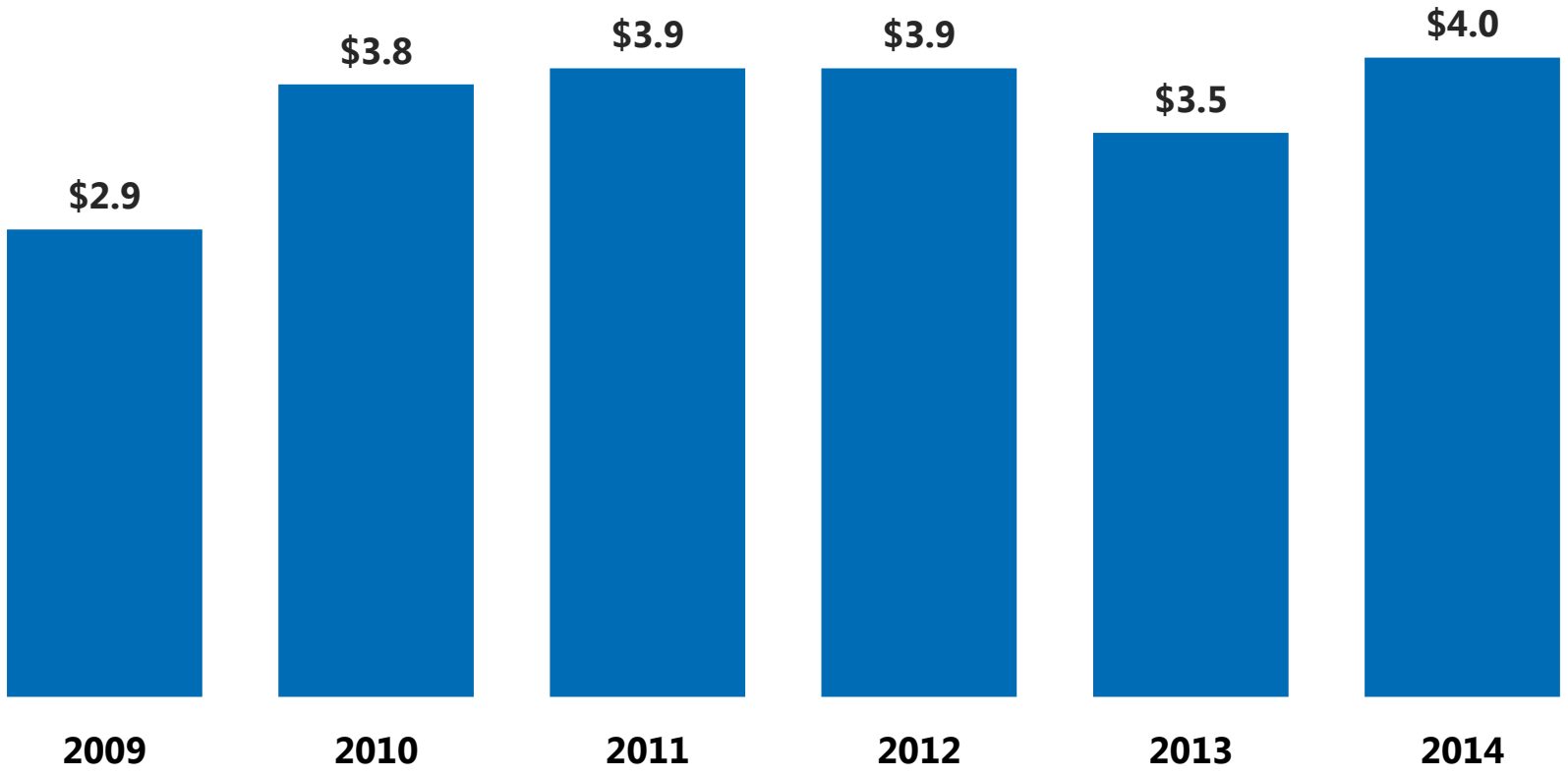
- Public safety and reliability
- Distribution Resources Plan (DRP)
- Grid readiness
- Electric vehicle charging and storage
- State environmental policy
- Transmission

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 • Trigger mechanism for fuel and purchased power adjustments at 5% variance level
Major Balancing Accounts • Fuel • Purchased power • Energy efficiency • Pension-related contributions	• Utility cost-recovery via balancing accounts represented more than 55% of 2014 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 cycle • Separate multi-year cost of capital proceeding

SCE Historical Capital Expenditures

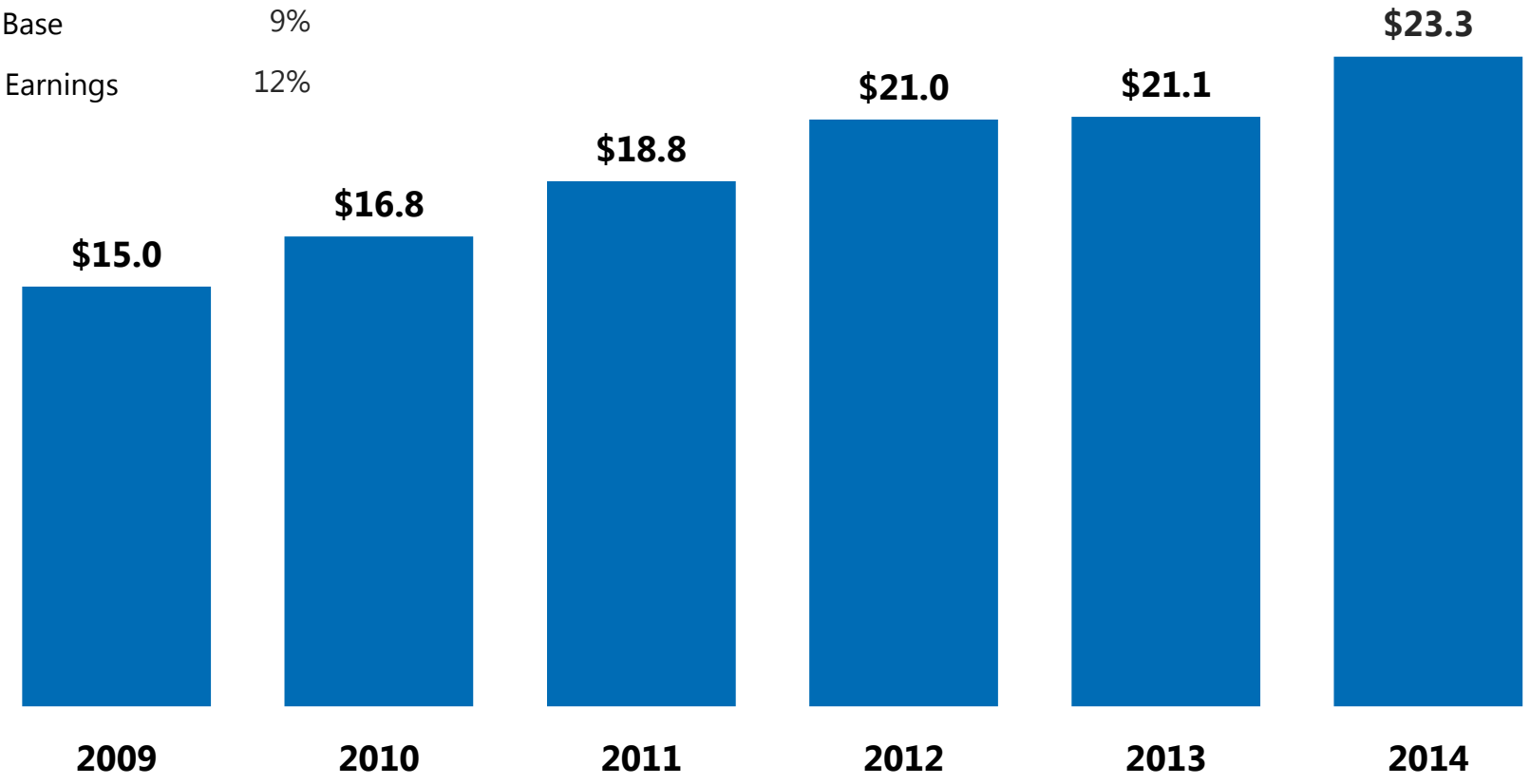
($ billions)



SCE Historical Rate Base and Core Earnings

($ billions)

2009 – 2014 CAGR	
Rate Base	9%
Core Earnings	12%

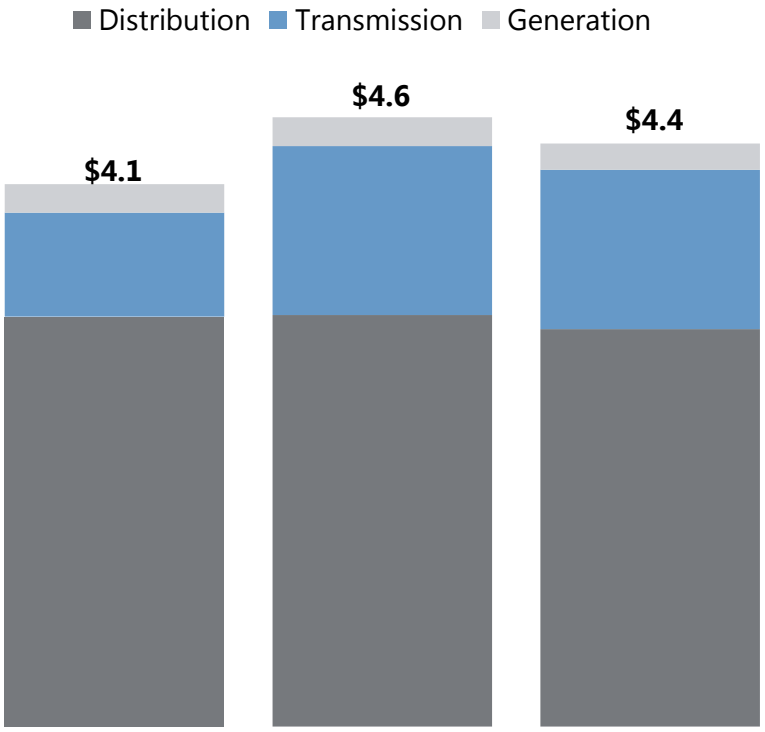


	2009	2010	2011	2012	2013	2014
Core EPS	$2.68	$3.01	$3.33	$4.10	$3.88	$4.68

Note: Recorded rate base, year-end basis. See Earnings Non-GAAP Reconciliations and Use of Non-GAAP Financial Measures in Appendix. 2013 and 2014 rate base excludes SONGS

SCE Capital Expenditures Forecast

($ billions)



	2015	2016	2017	2015-17 Total
Request	$4.1	$4.6	$4.4	**$13.1**
Range	$3.6	$4.0	$3.9	**$11.5**

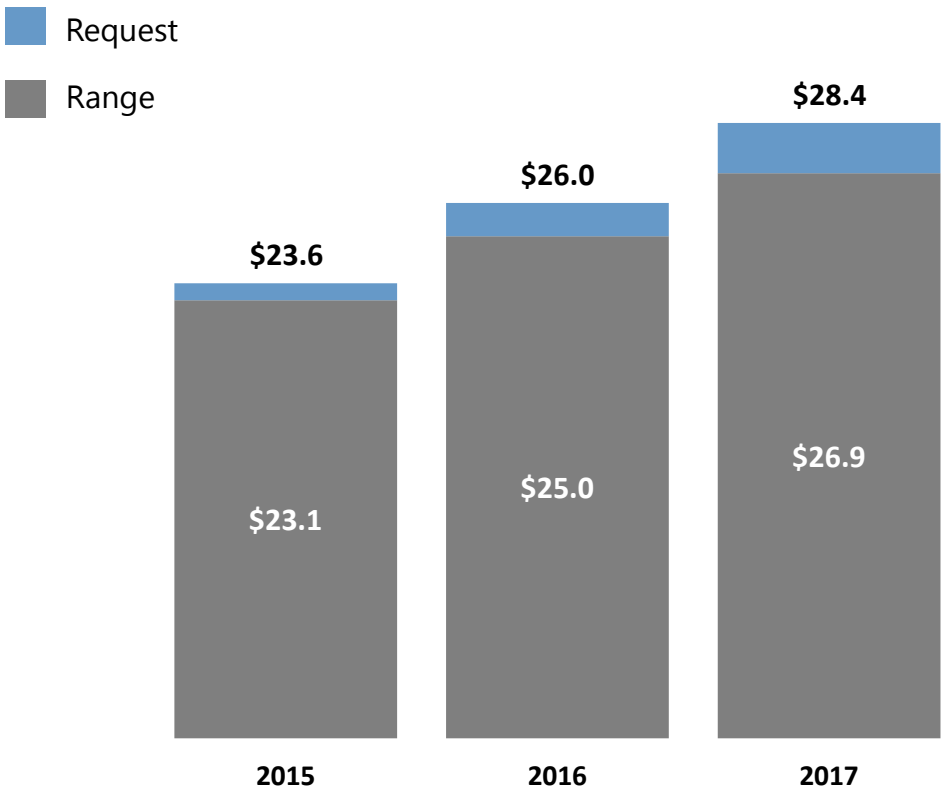
$11.5 – $13.1 billion forecasted capital program 2015-2017

- No change from prior forecast
- Growth driven by infrastructure replacement, reliability investments, distribution resources plan investments and public policy requirements

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% average annual rate base growth for 2015-2017

- No change from prior forecast
- FERC rate base includes Construction Work in Progress (CWIP) and is approximately 23% of SCE's rate base forecast by 2017
- Excludes SONGS regulatory asset

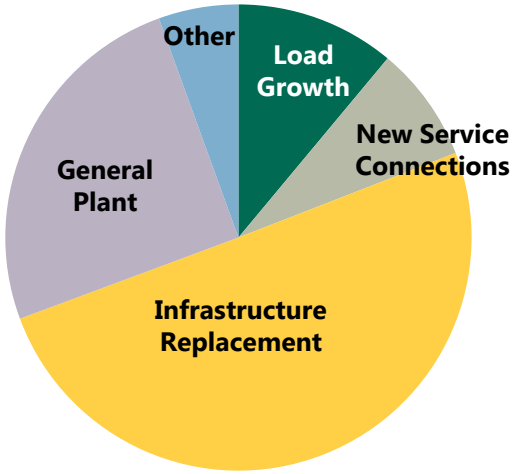
Note: Weighted-average year basis, 2015-2017 CPUC rate base requests and consolidation of CWIP projects. Rate base forecast range reflects capital expenditure forecast range

SCE System Investments

Distribution

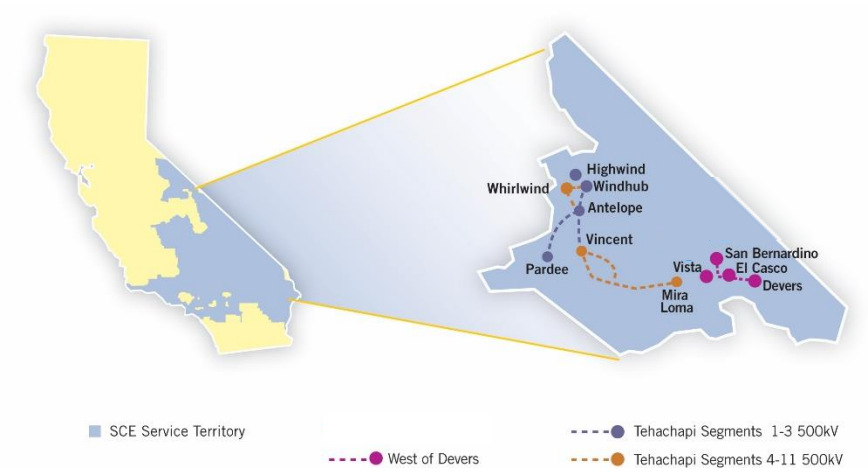
- Aging system reaching equilibrium replacement rate
- 2015 GRC request includes ~120% increase in infrastructure replacement

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



Transmission

- Large transmission projects:
  - Tehachapi 4-11 – $2.5 billion total project cost; remaining investment $0.4 billion; 2016-17 in service date
  - West of Devers – $1.0 billion total project cost; remaining investment $1.0 billion; 2019-20 in service date



Note: Total Project Costs are nominal direct expenditures, subject to CPUC and FERC cost recovery approval. Remaining transmission costs as of June 30, 2015

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]

Distribution Resources Plan

- Accelerate automation and control technology at optimal locations to manage two-way power flows with more dynamic voltage control
- DRP required under AB 327 to identify optimal locations, additional spending, and barriers to deploying distributed energy resources – filed July 1, 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
- West of Devers (2019-2020) incorporated from prior Transmission Plans in service beyond 2017

Energy Storage

- 290 MW utility owned investment opportunity 2015-2024

Other California Public Policy Requirements and Enabling Projects

- Electric vehicle charging infrastructure (SCE Charge Ready Program)
- 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

Distribution Grid of the Future

Current State

One-Way Electricity Flow

- System designed to generate electricity from large central plant
- Very few distributed energy resources
- Voltage relatively simple to maintain
- Limited situational awareness and visualization tools for grid operators

Renewable Generation Mandates

Subsidized Residential Solar

Lack of Electric Vehicle Charging Infrastructure

Future State

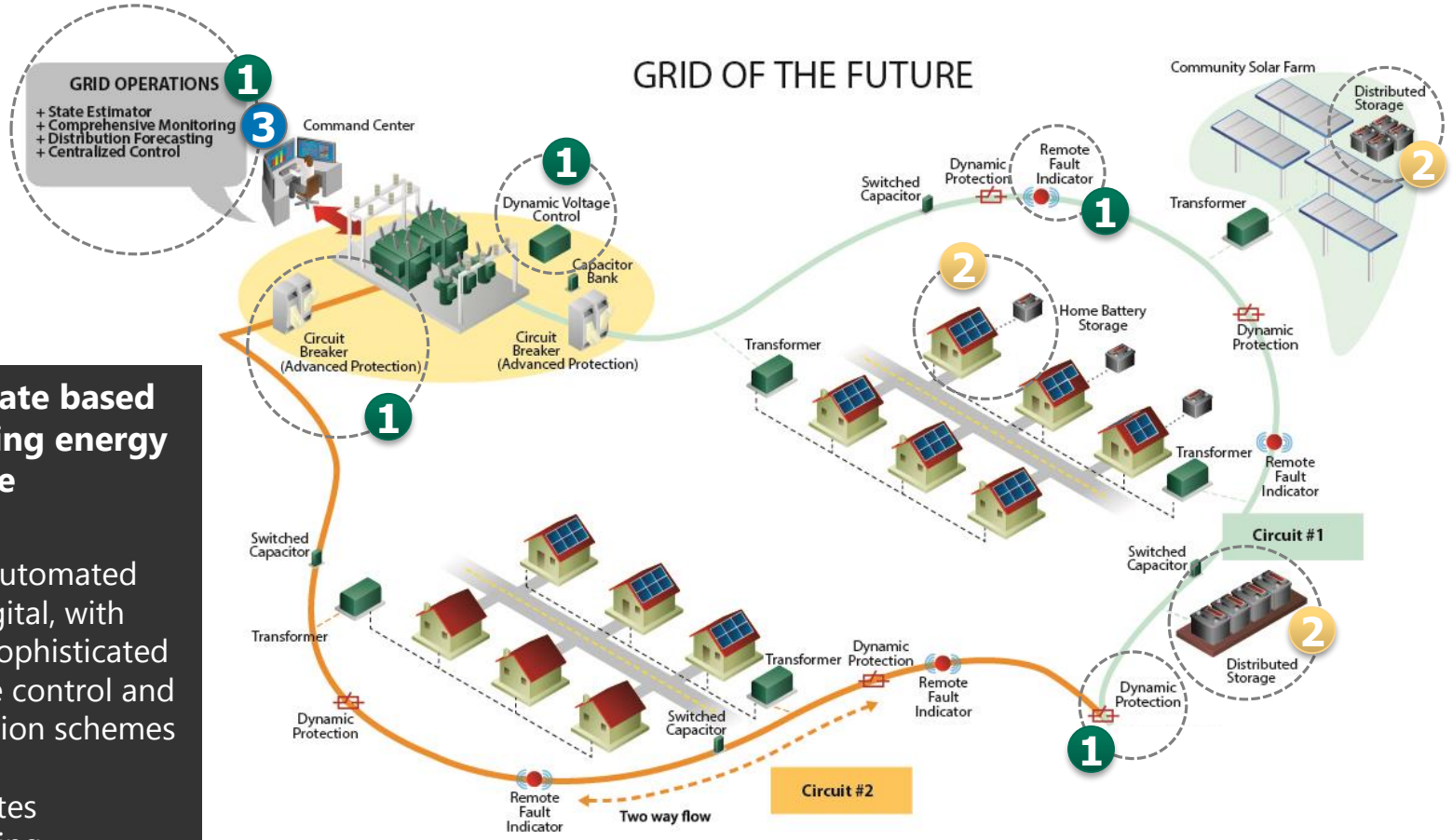
Variable, Two-Way Electricity Flow

- Distribution system at the center of the grid
- System designed to serve variable resources and customer demand
- Digital monitoring and control devices and advanced communications systems to manage two-way flows
- Improved data management and grid operations with cyber mitigation

Maximize Distributed Resources and Electric Vehicle Adoption

- Distribution grid infrastructure design supports customer choice and greater resiliency

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 Distribution Resources Plan

AB 327 required IOU submissions of Distribution Resources Plans (DRP) on July 1, 2015 to integrate increasing penetration of Distributed Energy Resources (DERs). Key provisions of the DRP filing include:

- Methodology/Tools for identifying optimal locations for DERs (includes distributed generation, energy storage, electric vehicle charging, energy efficiency and demand response)
- Enhance the electric system's capability to integrate more DERs at the distribution level through modernization of system planning tools, design and operations
- Technology recommendations (information technology, communications, system planning, voltage and frequency controls, etc.)

SCE's DRP includes a conceptual capital plan

- Estimated scope of work, technology roadmap, timeline, and capital and expense cost estimates
- Incremental to traditional general rate case expenditures; implementation recommendations proposed to be integrated into future general rate cases beginning with the 2018 filing
- Overall capital spending expected to be at least in the range of current forecast levels, although could result in higher spending pending CPUC approval in future GRCs

SCE Grid Modernization Road Map

SCE's July 1, 2015 DRP supports the Commission's proposed phased approach, which would be implemented over future General Rate Case (GRC) cycles

GRC Cycle	2015 - 2017	2018 - 2020	2021 +
Technology	Implement foundational information technology, communication systems, and system planning tools; begin grid reinforcement work	Expand automation and improve communications and control with Distributed Energy Resources; continue grid reinforcement work	Continue grid modernization, maximize benefits of Distributed Energy Resources and continue integrating into planning and operations
People and Process	Prepare organization and workforce to execute incremental work	Ramp up resources and develop talent pipeline	
Expected Result	Compliance, safety, and reliability; preparation for future grid state	New business opportunities enabled; full deployment of grid modernization	Prepare grid management systems to handle increased DER and support more grid transactions

SCE DRP Capital Expenditure Estimates

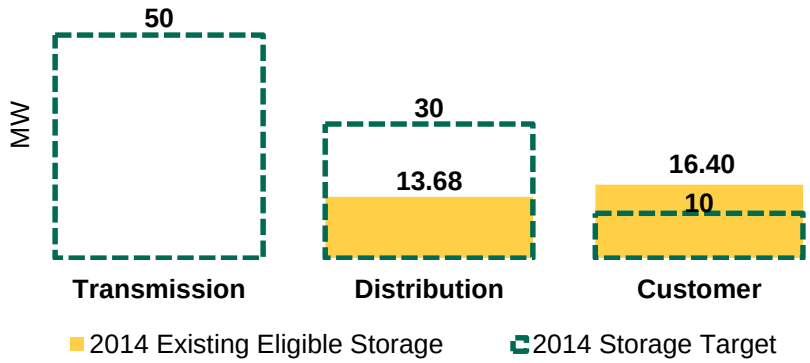
Time Period	Capital Expenditures		CPUC Approval Mechanism
2015-2017	Distribution Automation	$40-70 million	• Proposed memorandum account to record associated revenue requirement until expenditures are authorized by CPUC
	Substation Automation	$30-60 million	
	Communications Systems	$7-15 million	
	Technology Platforms and Applications	$130-200 million	
	Grid Reinforcement	$140-215 million	
	Total	**$347-560 million**	
2018-2020	Distribution Automation	$185-320 million	• Request recovery in 2018 GRC
	Substation Automation	$185-320 million	
	Communications Systems	$270-470 million	
	Technology Platforms and Applications	$215-375 million	
	Grid Reinforcement	$550-1,100 million	
	Total	**$1,405-2,585 million**	

SCE anticipates capital spending to continue at least in the range of current forecast levels, although could result in higher spending pending CPUC approval in future GRCs

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 began 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

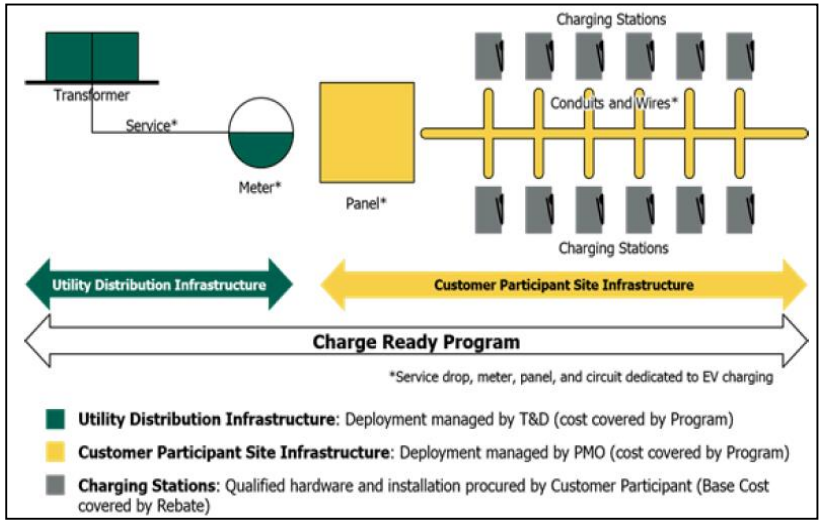


- Tehachapi Storage Project
- Irvine Smart Grid Demonstration Projects
- Large Energy Storage Test Apparatus
- Discovery Science Center
- Catalina Island Battery System
- Vehicle-to-Grid Program – LA Air Force Base
- Self-Generation Incentive Program
- Permanent Load Shifting Program

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

SCE Charge Ready Program

- October 2014, electric vehicle Charge Ready Program application submitted to CPUC (A.14-10-014)
- Pro-active, two-phased program over five years to support installation of up to 30,000 EV charging stations to be included in rate base
  - Phase 1: $22 million pilot program for 1,500 chargers and market education program (2015 – 2016)
  - Phase 2: $333 million for 28,500 chargers (2016 – 2020)
- On July 9th, SCE and 15 other parties filed a settlement agreement on Phase 1 which is awaiting CPUC approval
  - Would reduce rate base opportunity to $225 million if Phase 2 follows settled approach
- Addresses approximately 1/3 of forecast non-single family home charging demand in SCE territory in 2020



- Level 1 (110V) and Level 2 (240V) chargers with Demand Response capability
- As a general rule, 10 chargers per site minimum
- Participants own / operate / maintain chargers
- Capital cost per charging station: $11,400
- Rate base with rebate to participants – may be revised per Phase 1 settlement

SCE's electric vehicle Charge Ready Program supports Governor Brown's 2012 zero-emission vehicle Executive Order – 1.5 million EVs by 2025

SCE Key Regulatory Proceedings

Proceeding	Description	Next Steps
	Capital	
2015 GRC Application (A.13-11-003)	Rate setting for CPUC 3-year cycle 2015 – 17	Proposed and final decision expected in 2015
Cost of Capital Application	Capital structure and return on equity	Next filing scheduled for April 2016
Distribution Resources Plan OIR (R.14-08-013)	Grid investments to integrate distributed energy resources	SCE plan submitted July 1; CPUC schedule pending
FERC Formula Rates	Transmission rate setting with annual updates	ROE moratorium expired July 1, 2015; annual update due December 2015; settlement in place through December 2017
	Rate Design	
Rate Design OIR (R.12-06-013)	Tiers, fixed charges, time of use (Phase 1); Net metering tariff (R.14-01-002)	Phase 1 decision issued July 3, 2015; NEM testimony due Q3 2015
	Cost Recovery	
SONGS OII (I.12-10-013)	Motion on sanctions/reopening the settlement and Application For Rehearing pending	Decision on motion and AFR; OII open through September 27, 2015 but can be extended
2012 LTPP Tracks 1 & 4 RFO (D.13-02-015)	Local capacity/preferred resources to replace SONGS and once through cooling plants	2,221 MW, including 262 MW storage, submitted for PUC approval November 2014
Energy Storage RFO	Solicitation for 16.3 MW launched December 2014	Short list notification May 15; final selection September 14
Energy Resource Recovery Account (ERRA)	Annual forecast and review of fuel and purchased power costs	2015 settlement for no increase filed July 2015; 2016 forecast submitted May 2015

SCE 2015 CPUC General Rate Case

November 2013, 2015 GRC Application A.13-11-003 sets 2015 – 2017 base revenue requirement

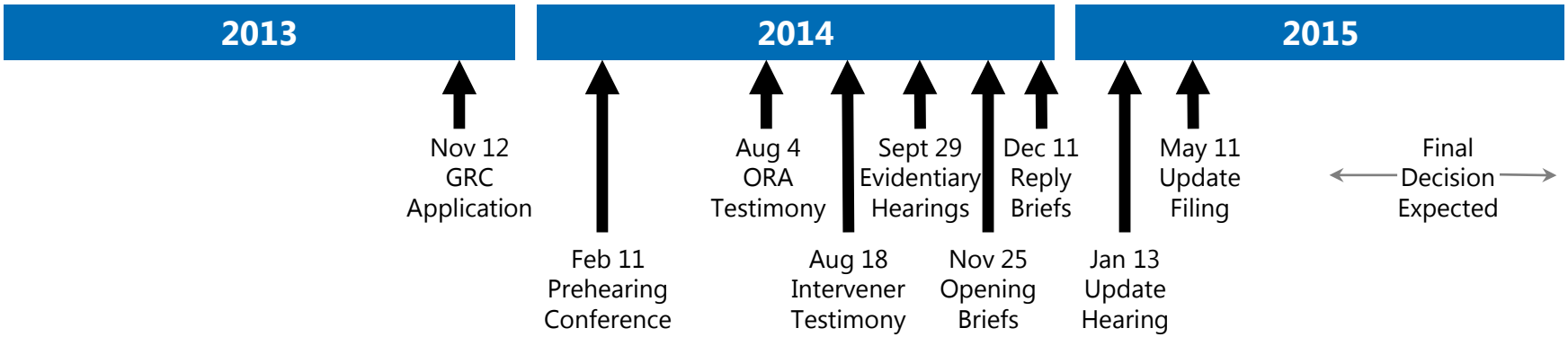
- Includes operating costs and CPUC jurisdictional capital
- Excludes fuel and purchased power (and other utility cost-recovery activities), cost of capital, and FERC jurisdictional transmission

2015 revenue requirement request of $5.512 billion

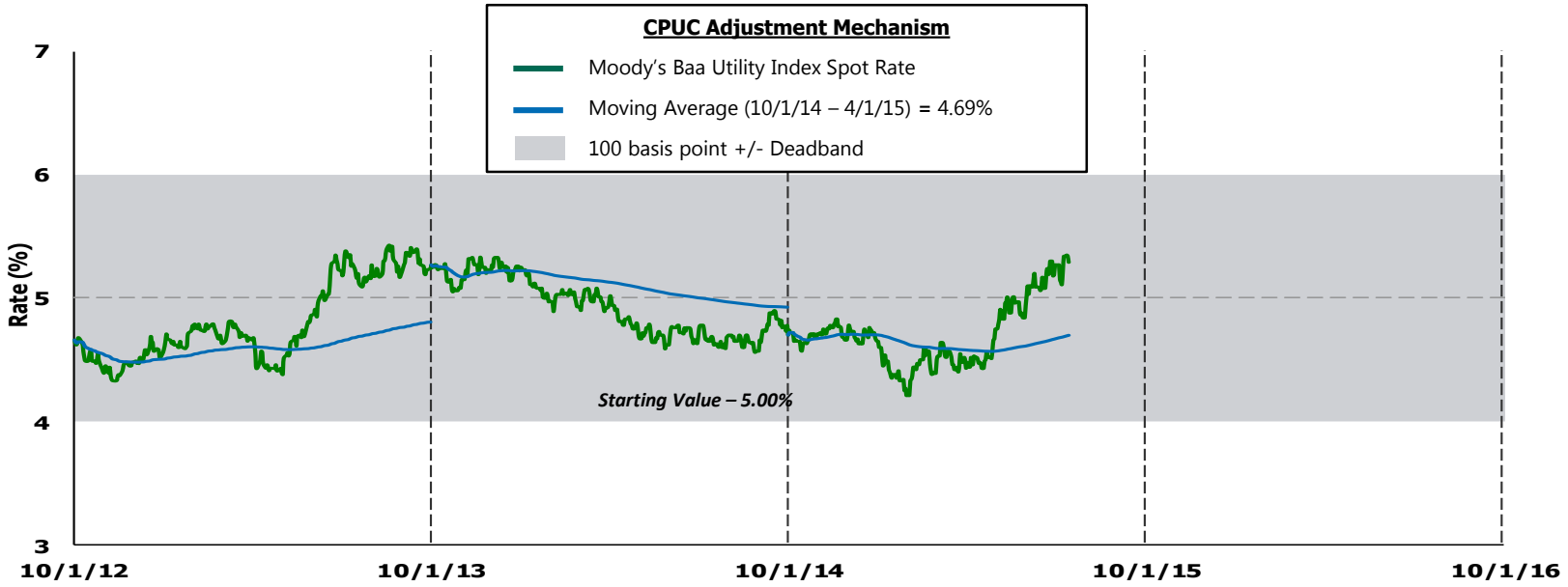
- $121 million decrease from presently authorized base rates based on May 11th update filing
- Post test year requested year-over-year increase of $236 million in 2016 and additional increase of $320 million in 2017

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

Current CPUC schedule does not specify a proposed decision timeframe



CPUC and FERC Cost of Capital



CPUC – 48% common equity and Return on Equity (ROE) adjustment mechanism has been extended through 2016

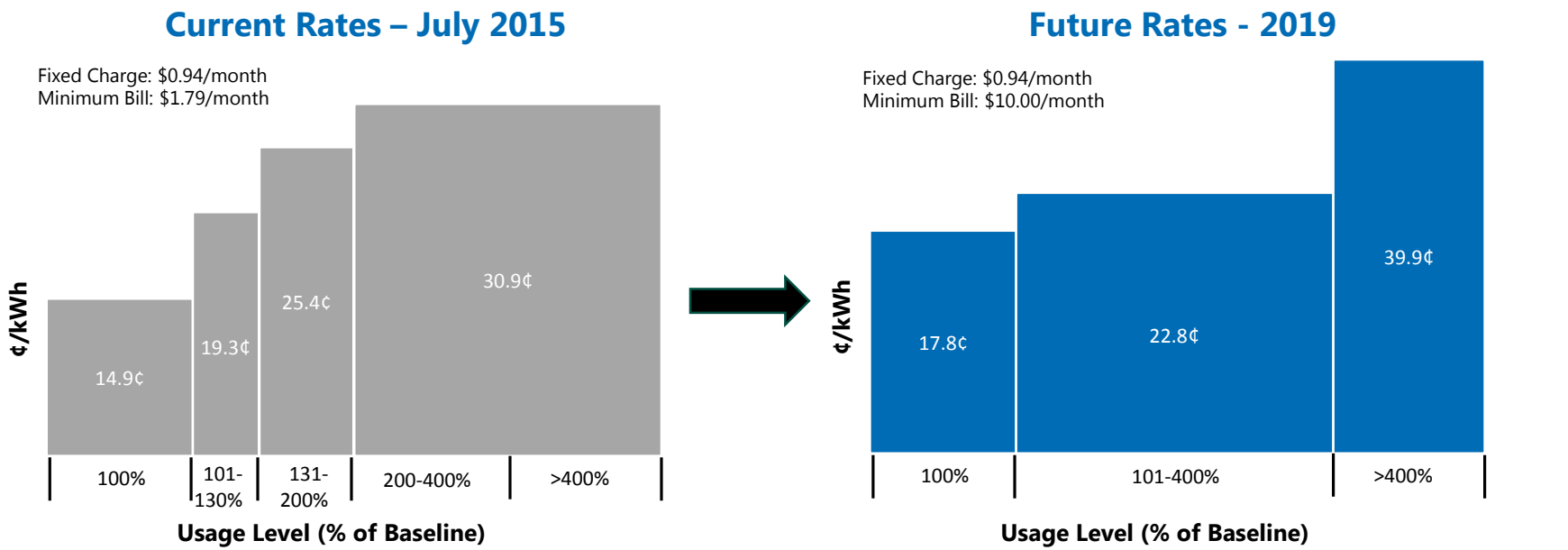
- Weighted average authorized cost of capital – 7.90%
- ROE adjustment based on 12-month average of Moody's Baa utility bond rates, measured from Oct. 1 to Sept. 30
- If index exceeds 100 bps deadband from starting index value, authorized ROE changes by half the difference
- Starting index value based on trailing 12 months of Moody's Baa index as of September 30, 2012 – 5.00%
- Application in April 2016 for 2017 Cost of Capital – adjustment mechanism continues in the interim

FERC – comparable to CPUC 10.45% ROE

- Includes 9.30% base + 50 bps CAISO participation plus project incentives
- Moratorium on filing ROE changes expired July 1, 2015
- FERC Formula recovery mechanism in effect through December 31, 2017

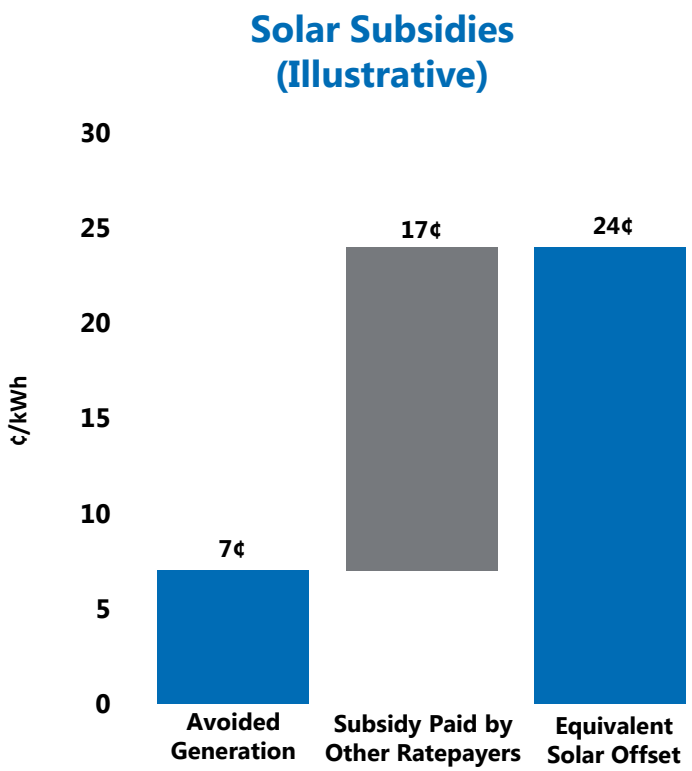
Residential Rate Design OIR

- CPUC Order Instituting Ratemaking R.12-06-013 includes comprehensive review of residential rate structure including a future transition to time of use rates
- July 2015 CPUC Decision includes:
  - Transition to 2 tiered rates by 2019
  - "Super User Electric Surcharge" for usage 400% above baseline (~4% of current residential load)
  - Continue fixed charge at $0.94/month; allows for consideration of increased fixed charges in future
  - Minimum bills up to $10/month which applies to delivery revenue only
- Net Energy Metering (R.14-07-002): successor tariff due Q4 2015



Note: Graphs not to scale. 2019 rate levels are based on current revenue requirements

SCE Residential Net Metering Rate Structure



SCE's Rate Developments:

- Residential solar customer generation offsets total retail rate via Net Energy Metering (NEM) structure
- Through tiered rate flattening, Residential Rate OIR decision will reduce subsidy paid by non-solar customers by about 20%
- 20-year NEM grandfathering at retail rate for installations up to 5% cap (2,240 MW for SCE) interconnected before July 2017
- On August 3rd, SCE (and other parties) will file rate proposals with the CPUC that are more reflective of distributed energy systems' total costs and benefits

SCE 2014 Net Energy Metering Statistics:

- 103,900 combined residential and non-residential projects – 880 MW installed (of 2,240 MW cap)
  - 99.5% solar
  - 100,300 residential – 500 MW
  - 3,600 non-residential – 380 MW
- Approximately 1,270,000 kWh / year generated

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

SCE Operational Excellence

Defining Excellence

Top Quartile

- Safety
- Cost efficiency
- Reliability
- Customer service

Optimize

- Capital productivity
- Purchased power cost

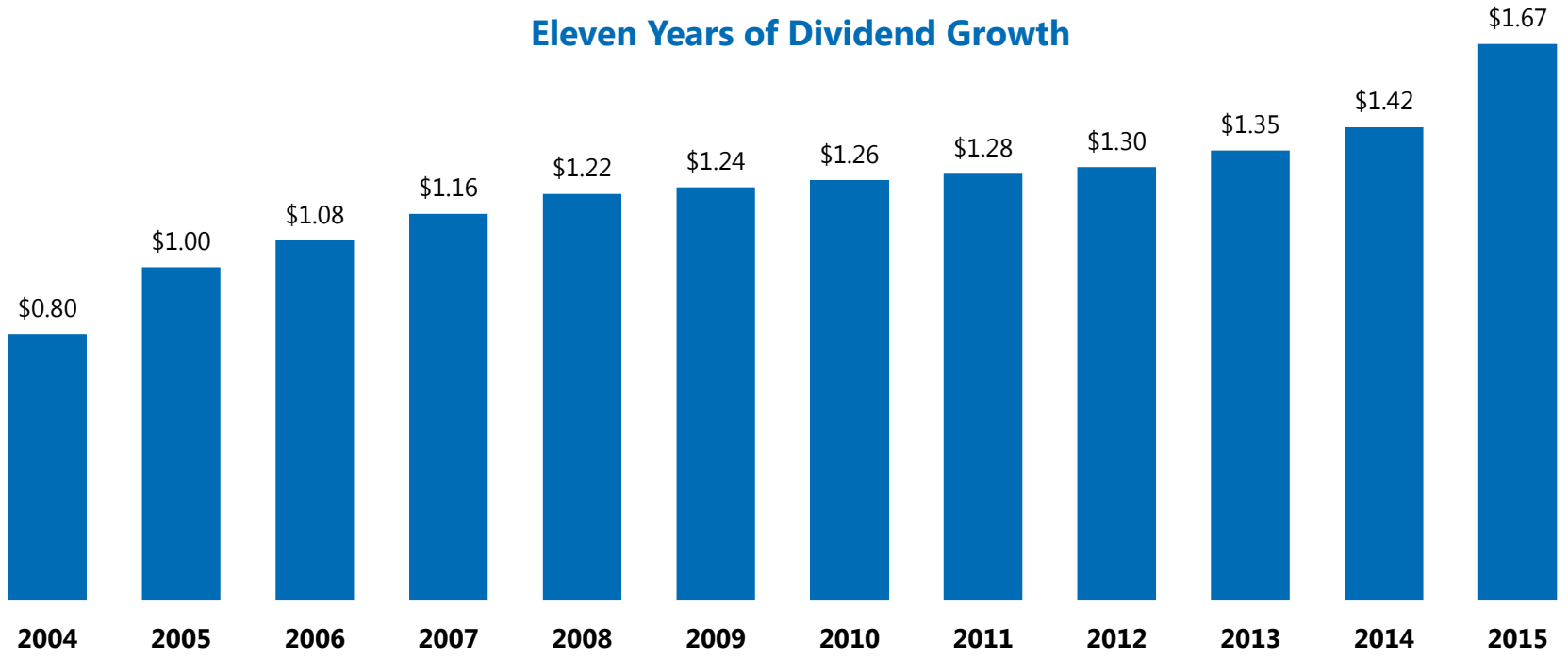
High performing, continuous improvement culture

Ongoing Operational Excellence Efforts

Measuring Excellence

- Employee and public safety metrics
- System reliability (SAIDI, SAIFI, MAIFI)
- J.D. Power customer satisfaction
- O&M cost per customer
- Reduce system rate growth with O&M / purchased power cost reductions

EIX Annual Dividends Per Share

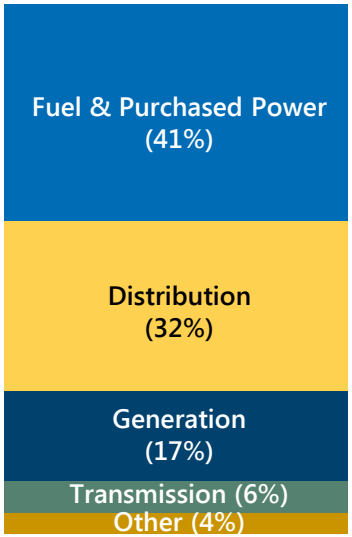


EIX targets a payout ratio of 45 – 55% of SCE core earnings and plans to return to target payout ratio in steps, over time

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

Appendix

SCE 2014 Bundled Revenue Requirement



	2014 Bundled Revenue Requirement $millions	¢/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

60% utility earnings activities

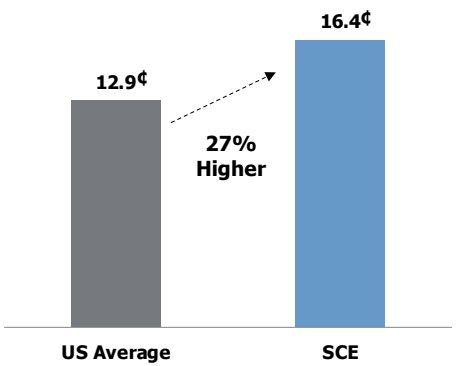
Total Bundled Revenue Requirement ($millions)	$12,260
÷ Bundled kWh (millions)	73,249
= Bundled Systemwide Average Rate (¢/kWh)	16.7¢

SCE Systemwide Average Rate History (¢/kWh)				
2010	2011	2012	2013	2014
14.3	14.1	14.3	15.9	16.7

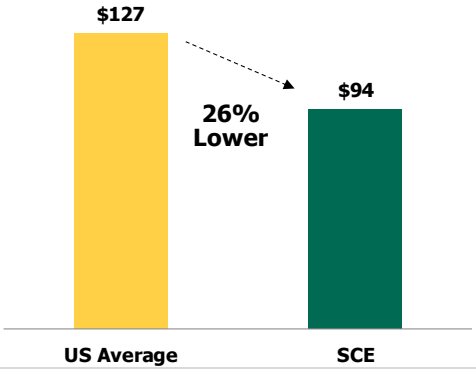
Note: Rates in effect as of July 7, 2014, based on forecast. Represents bundled service which excludes Direct Access customers that do not receive generation services

SCE 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
  - 42% 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 2014

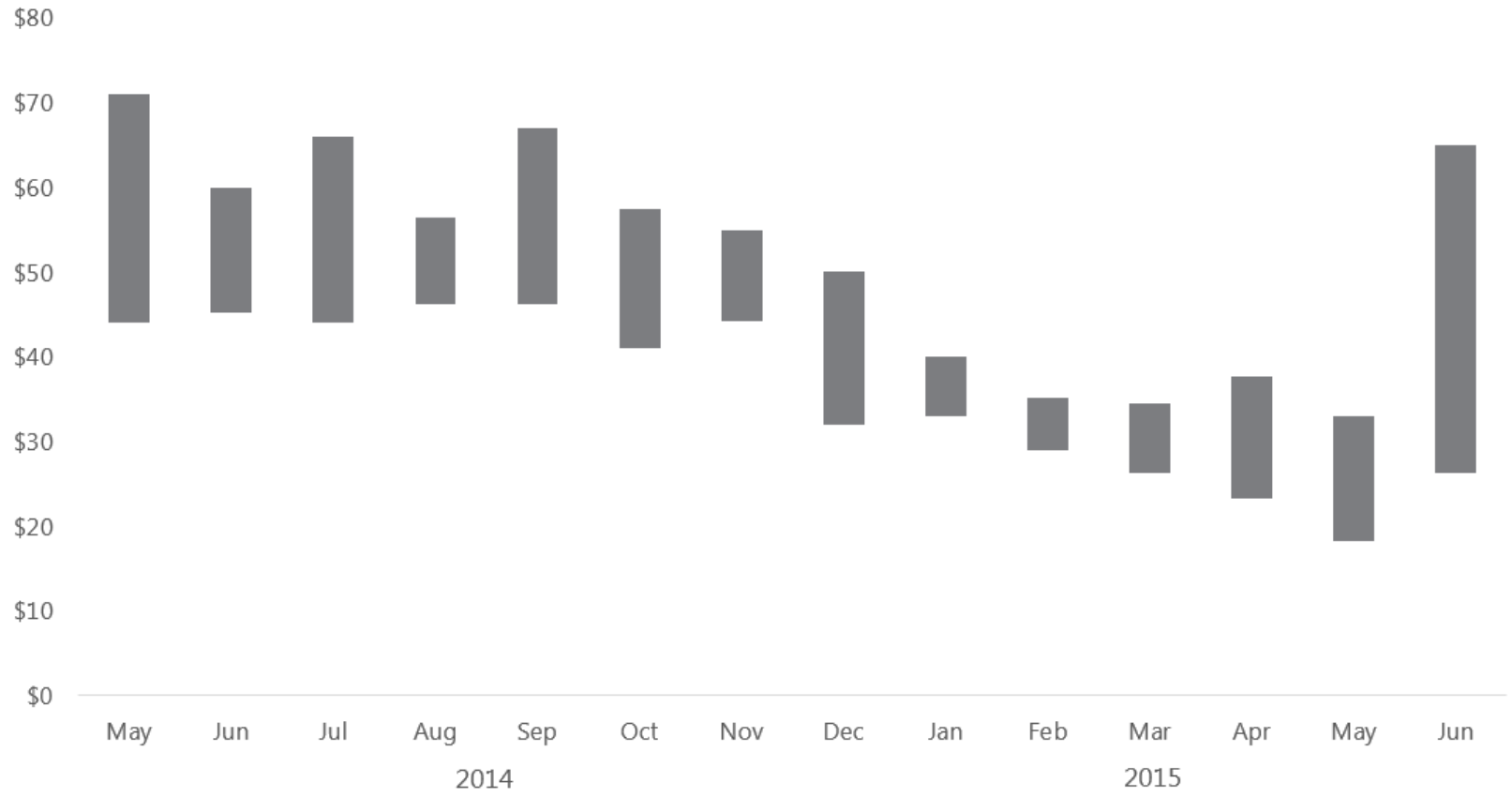
SCE Customer Demand Trends

Kilowatt-Hour Sales (millions of kWh)	YTD 2015	2014	2013	2012	2011
Residential	12,782	30,115	29,889	30,563	29,631
Commercial	20,104	42,127	40,649	40,541	39,622
Industrial	3,792	8,417	8,472	8,504	8,490
Public authorities	2,264	4,990	5,012	5,196	5,206
Agricultural and other	864	2,025	1,885	1,676	1,318
Subtotal	*39,806*	*87,674*	*85,907*	*86,480*	*84,267*
Resale	414	1,312	1,490	1,735	3,071
Total Kilowatt-Hour Sales	**40,220**	**88,986**	**87,397**	**88,215**	**87,338**
Customers					
Residential	4,381,124	4,368,897	4,344,429	4,321,171	4,301,969
Commercial	559,594	557,957	554,592	549,855	546,936
Industrial	10,893	10,782	10,584	10,922	11,370
Public authorities	46,343	46,234	46,323	46,493	46,684
Agricultural	21,401	21,404	21,679	21,917	22,086
Railroads and railways	118	105	99	83	82
Interdepartmental	22	22	23	24	22
Total Number of Customers	**5,019,495**	**5,005,401**	**4,977,729**	**4,950,465**	**4,929,149**
Number of New Connections	**12,626**	**29,879**	**27,370**	**22,866**	**19,829**
Area Peak Demand (MW)	**N/A**	**23,055**	**22,534**	**21,996**	**22,443**

Note: See 2014 Edison International Financial and Statistical Reports for further information

Wholesale Electricity Prices, May 2014-June 2015

(Southern California)



Source: Energy Information Administration, July 2015. Data is for SP-15 Nodes

The Future of California Energy Policy

January 2015, Governor Brown's inauguration speech outlined environmental objectives for 2030 which are currently being considered by the legislature (SB 350)

- Increase renewables (RPS) to 50%
- Reduce petroleum use in cars by 50%
- Double efficiency of existing buildings

Utility Role

Renewables

Legislative action, regulation, grid investment

- Renewable Portfolio Standard (RPS) – mandate, currently 33% by 2020
- Clean Energy Standard (CES) – emissions targets met through optimization of renewables, transportation, energy efficiency

Electric Vehicles

Utility participation through infrastructure investment

- SCE Charge Ready application
- Distribution grid investments to meet EV impact

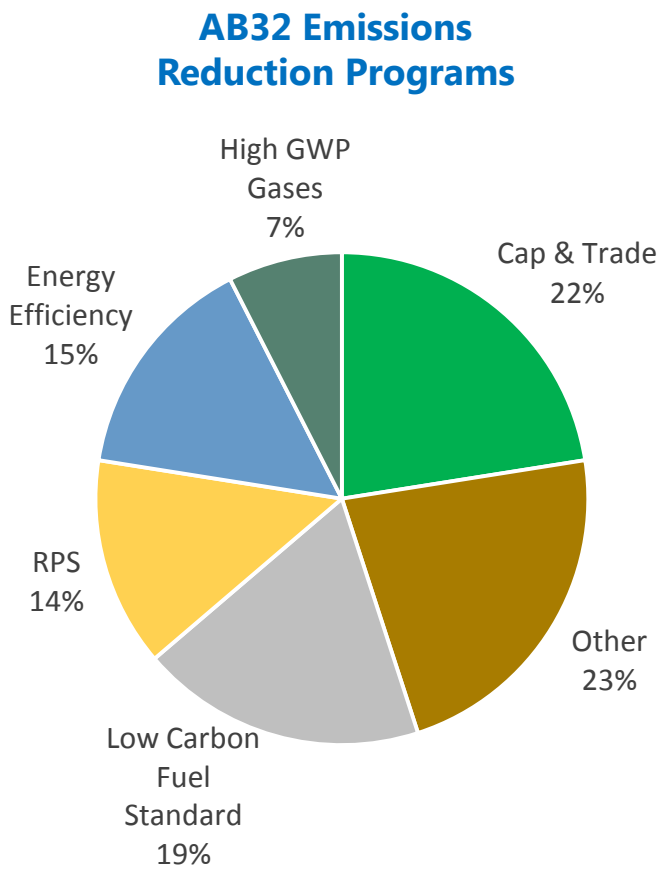
Energy Efficiency

Continuation of utility programs and earnings incentive mechanism

- SCE 2015 program budget: $333 million
- $0.05 per share 2015 earnings potential

California Cap and Trade Program

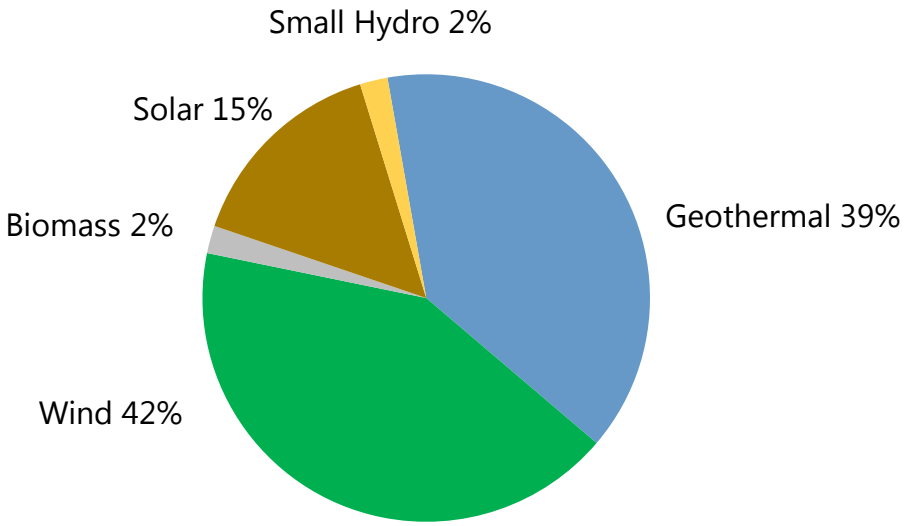
- Assembly Bill 32 (2006) – reduces State greenhouse gas (GHG) emissions to 1990 levels by 2020 (~16% reduction)
- Cap and trade program basics:
  - State-wide cap in 2013 – decreases over time
  - Compliance met through allowances, offsets, or emissions reductions
  - Excess allowances sold, or "banked" for future use
  - January 2014 – merger with Quebec cap and trade program
- SCE received 32.3 million 2013 allowances vs. a financial exposure to only 21.9 million metric tons of GHG emissions that same year
- 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



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 need to increase its renewable purchases by 7.4 billion kWh, or 42%

Actual 2014 Renewable Resources: 23.4% of SCE's portfolio



While SCE is on track to meet the 33% renewables target by 2020

SCE Energy Efficiency Programs

Energy efficiency programs updated for 2013 – 2015

- 2015 budget of $333 million
- Savings targets of 983 GWh and 160.1 MW for 2015 – Reduced goals reflect CPUC-identified potential for energy efficiency

Energy efficiency earnings incentive mechanism modified

- CPUC approved new incentive mechanism for 2013 – 2015 activities comprised of performance rewards and management fees

SCE Energy Efficiency Earnings Summary

Program Year	Total Requested	Received	Pending CPUC Approval
2010	$15.1 million $0.03/share	$15.1 million $0.03/share (2012)	
2011	$18.6 million $0.04/share	$13.6 million $0.03/share (2013)	$5.0 million $0.01/share
2012	$16.2 million $0.03/share	$10.8 million $0.02/share (2013)	$1.2 million $0.00/share
2013 (Part 1)	$14.2 million $0.03/share	$10.8 million $0.02/share (2014)	
2013 (Part 2)	$9.9 million $0.03/share	Expected in 2015	
2014 (Part 1)	$12.1 million $0.03/share	Expected in 2015	
2014 (Part 2)	$14.4 million $0.04/share	Expected in 2016	

Note: Additional program year 2013 award request, and request for $5.0 million and $1.2 million currently pending, expected to be submitted in 2015

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

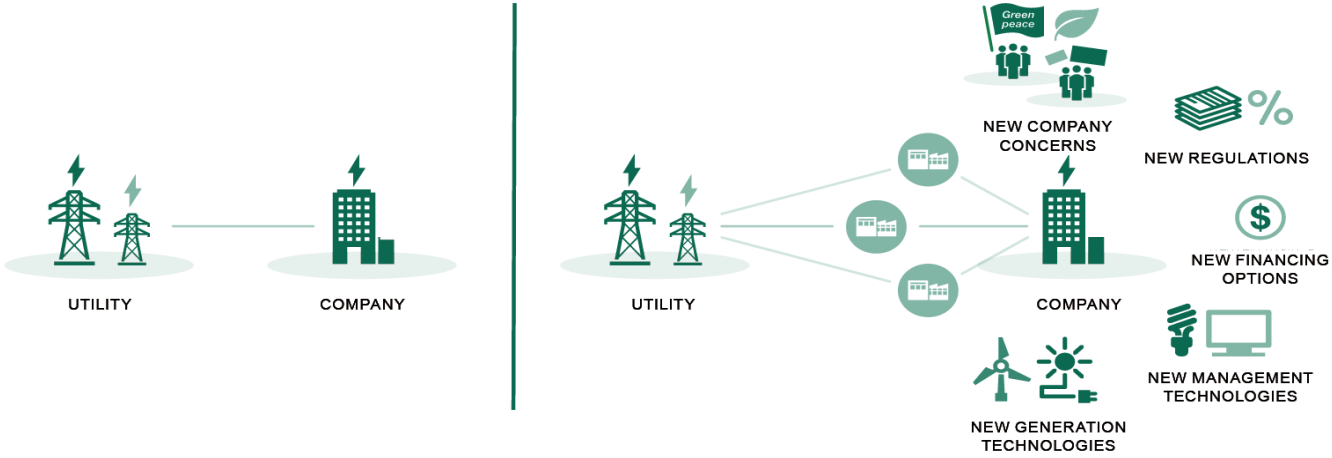
- Invest in, build, and operate the next generation electric grid
- Operational and service excellence
- Enable California public policies

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

Edison Energy Focus: Commercial & Industrial

Changing Customer Needs



The Opportunity: Trusted Advisor

- Create energy services that help simplify and optimize energy needs for commercial & industrial customers:
  - Help customers better value energy optimization, paving the way for greater third party energy services
  - Help customers manage through potential technological / regulatory changes

Evolving customer needs and uncertainty around changing technologies and regulation create a business opportunity for a trusted advisor role

Grid Assurance™ Overview

On June 10th, eight electric utilities and energy companies announced a MOU to pursue the development of Grid Assurance, a limited liability company that plans to offer subscribers cost-effective solutions for enhancing grid resiliency and protecting customers from prolonged transmission outages

- Grid Assurance is intended to address potential high impact events on the bulk transmission systems:
  - Entity will own critical equipment with long manufacturing lead times to account for risk beyond what is covered by "operational spares" (e.g., BES transformers, breakers, etc.)
  - Entity will provide secure, off-site storage in strategic locations, and support the delivery of equipment transportation and logistics services
  - Subscribers will pay a cost-of-service based subscription fee for access to inventory and will have rights to call upon inventory following a "Qualifying Event" such as physical attacks, electromagnetic pulses, solar storms, cyberattacks, earthquakes and severe weather events
  - Regulatory construct will provide cost certainty and cost recovery similar to FERC formula rates for transmission assets
  - Subscription to the sparing service will be available to all transmission owning entities
- Contingent on regulatory approvals, Grid Assurance is expected to begin accepting subscribers and identifying inventory in 2016

Edison Transmission is one of the eight companies pursuing Grid Assurance

Second Quarter Earnings Summary

	Q2 2015	Q2 2014	Variance
Core Earnings Per Share (EPS)[1]			
SCE	$1.18	$1.11	$0.07
EIX Parent & Other	(0.02)	(0.03)	0.01
Core EPS[1]	**$1.16**	**$1.08**	**$0.08**
Non-Core Items[2]			
SCE	$ –	$ –	$ –
EIX Parent & Other	–	–	–
Discontinued Operations	–	0.56	(0.56)
Total Non-Core	**$ –**	**$0.56**	**$(0.56)**
Basic EPS	**$1.16**	**$1.64**	**$(0.48)**
Diluted EPS	**$1.15**	**$1.63**	**$(0.48)**

SCE Key Core EPS Drivers		
Lower revenue[3,4]		$(0.03)
- CPUC GRC revenue deferral	(0.09)	
- FERC revenue and other	0.06	
Lower O&M[5]		0.01
Higher depreciation		(0.06)
Lower net financing costs		0.03
Income taxes		0.19
- 2015 change in uncertain tax positions	0.31	
- 2014 change in uncertain tax positions	(0.09)	
- Incremental repair deductions[3]	0.09	
- Lower tax benefits	(0.12)	
Other items		(0.07)
- Generator settlements	(0.03)	
- Higher property taxes[6]	(0.02)	
- Other	(0.02)	
Total		$0.07

EIX Key Core EPS Drivers	
Lower corporate expenses	$0.01

1. See Earnings Non-GAAP Reconciliations and Use of Non-GAAP Financial Measures in Appendix
2. Non-core items for the quarter ended June 30, 2014, included $0.56 income from discontinued operations related to the EME settlement
3. SCE deferred revenues of $0.09 related to incremental repair deductions pending the outcome of the 2015 GRC
4. Excludes San Onofre revenue of $0.04, which was offset by amortization of regulatory assets of $(0.06) and O&M of $0.02
5. Includes non-San Onofre severance of $0.02 and $0.01 for the quarters ended June 30, 2015 and 2014, respectively
6. Includes San Onofre property tax refund of $0.01 related to replacement steam generators for the quarter ended June 30, 2014

YTD 2015 Earnings Summary

	YTD 2015	YTD 2014	Variance
Core Earnings Per Share (EPS)[1]			
SCE	$2.12	$2.04	$0.08
EIX Parent & Other	(0.06)	(0.06)	–
Core EPS[1]	**$2.06**	**$1.98**	**$0.08**
Non-Core Items[2]			
SCE	$ –	$(0.29)	$0.29
EIX Parent & Other	0.02	–	0.02
Discontinued Operations	–	0.49	(0.49)
Total Non-Core	**$0.02**	**$0.20**	**$(0.18)**
Basic EPS	**$2.08**	**$2.18**	**$(0.10)**
Diluted EPS	**$2.06**	**$2.17**	**$(0.11)**

SCE Key Core EPS Drivers		
Lower revenue[3,4]		$(0.02)
- CPUC GRC revenue deferral	(0.16)	
- FERC revenue and other	0.14	
Higher depreciation		(0.10)
Lower net financing costs		0.05
Income taxes		0.21
- 2015 change in uncertain tax positions	0.31	
- 2014 change in uncertain tax positions	(0.09)	
- Incremental repair deductions[3]	0.16	
- Lower tax benefits	(0.17)	
Other items		(0.06)
- Generator settlements	(0.03)	
- Property taxes and other[5]	(0.03)	
Total[6]		$0.08

1. See Earnings Non-GAAP Reconciliations and Use of Non-GAAP Financial Measures in Appendix
2. Non-core items for the six months ended June 30, 2014, included $0.29 charge related to San Onofre settlement and $0.49 income from discontinued operations related to the EME settlement and revised tax estimate of EME deconsolidation
3. SCE deferred revenues of $0.16 related to incremental repair deductions pending the outcome of the 2015 GRC
4. Excludes San Onofre revenue of $0.06, which was offset by amortization of regulatory assets of $(0.12), interest expense of $(0.01) and O&M of $0.07
5. Includes San Onofre property tax refund of $0.01 related to replacement steam generators for the six months ended June 30, 2014
6. Includes non-San Onofre severance of $0.02 and $0.01 for the six months ended June 30, 2015 and 2014, respectively

SCE Results of Operations – Full-Year 2014

($ 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

	2014			2013		
	Utility Earning Activities	Utility Cost-Recovery Activities	Total Consolidated	Utility Earning Activities	Utility Cost-Recovery Activities	Total Consolidated
Operating revenue	$6,831	$6,549	$13,380	$6,602	$5,960	$12,562
Purchased power and fuel	—	5,593	5,593	—	4,891	4,891
Operation and maintenance	2,106	951	3,057	2,348	1,068	3,416
Depreciation, decommissioning and amortization	1,720	—	1,720	1,622	—	1,622
Property and other taxes	318	—	318	307	—	307
Impairment and other charges	163	—	163	575	—	575
Total operating expenses	4,307	6,544	10,851	4,852	5,959	10,811
Operating income	2,524	5	2,529	1,750	1	1,751
Interest expense	(528)	(5)	(533)	(519)	(1)	(520)
Other income and expenses	43	—	43	48	—	48
Income before income taxes	2,039	—	2,039	1,279	—	1,279
Income tax expense	474	—	474	279	—	279
Net income	1,565	—	1,565	1,000	—	1,000
Preferred and preference stock dividend requirements	112	—	112	100	—	100
Net income available for common stock	$1,453	$—	$1,453	$900	$—	$900
Core earnings			$1,525			$1,265
Non-core earnings			(72)			(365)
Total SCE GAAP earnings			$1,453			$900

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

2015 Financial Assumptions

($ billions)

SCE Capital Expenditures

Distribution	$3.1
Transmission	0.8
Generation	0.2
Request	**$4.1**
Range	**$3.6**

SCE Weighted Average Rate Base

Distribution	$16.0
Transmission	5.4
Generation	2.2
Request	**$23.6**
Range	**$23.1**

SCE Authorized Cost of Capital

CPUC Return on Equity	10.45%
CPUC Capital Structure	48% equity
	43% debt
	9% preferred
FERC Return on Equity	Comparable to CPUC ROE

Other SCE Items

- SONGS regulatory asset financing completed January 2015
- Energy efficiency potential up to $0.05 per share
- Revenues recorded at 2014 levels until 2015 GRC decision is received (retroactive to January 1, 2015)
- $0.16 per share deferred revenues in YTD period for incremental repair deductions pending 2015 GRC decision

EIX will provide 2015 earnings guidance after a final decision on the SCE 2015 General Rate Case

Earnings Non-GAAP Reconciliations

($ millions)

Reconciliation of EIX Core Earnings to EIX GAAP Earnings

Earnings Attributable to Edison International	Q2 2015	Q2 2014	YTD 2015	YTD 2014
Core Earnings				
SCE	$384	$362	$689	$666
EIX Parent & Other	(6)	(10)	(17)	(20)
Core Earnings	**$378**	**$352**	**$672**	**$646**
Non-Core Items				
SCE	$ –	$ –	$ –	$(96)
EIX Parent & Other	1	–	6	–
Discontinued operations	–	184	–	162
Total Non-Core	**$1**	**$184**	**$6**	**$66**
Basic Earnings	**$379**	**$536**	**$678**	**$712**

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	2009	2010	2011	2012	2013	2014	CAGR
Core EPS	**$2.68**	**$3.01**	**$3.33**	**$4.10**	**$3.88**	**$4.68**	**12%**
Non-Core Items							
Tax settlement	0.94	0.30	—	—	—	—	
Health care legislation	—	(0.12)	—	—	—	—	
Regulatory and tax items	0.14	—	—	0.71	—	—	
Impairment and other charges	—	—	—	—	(1.12)	(0.22)	
Total Non-Core Items	*1.08*	*0.18*	—	*0.71*	*(1.12)*	*(0.22)*	
Basic EPS	**$3.76**	**$3.19**	**$3.33**	**$4.81**	**$2.76**	**$4.46**	**4%**

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

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.

EIX Investor Relations Contact

Scott Cunningham, Vice President	(626) 302-2540	scott.cunningham@edisonintl.com
Allison Bahen, Senior Manager	(626) 302-5493	allison.bahen@edisonintl.com