FILED
6-23-16
04:59 PM

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Assess Peak Electricity Usage Patterns and Consider Appropriate Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payments.	R.15-12-012 (Filed December 17, 2015)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) NOTICE OF *EX PARTE* COMMUNICATION

FADIA RAFEEDIE KHOURY
R. OLIVIA SAMAD

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-3477
Facsimile: (626) 302-7740
E-mail: Olivia.Samad@sce.com

Dated: **June 23, 2016**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Assess Peak Electricity Usage Patterns and Consider Appropriate Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payments.	R.15-12-012 (Filed December 17, 2015)

<u>SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) NOTICE OF *EX PARTE* COMMUNICATION</u>

Pursuant to Rule 8.4 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Southern California Edison Company (SCE) hereby gives notice of the following *ex parte* communication.

On Thursday, June 23, 2016, Mr. Russell Garwacki, Director of Pricing Design and Research, and Mr. Reuben Behlihomji, Manager of Marginal Cost, gave an oral presentation entitled, "Time Differentiated Distribution Costs & TOU Period Determination" at a panel of the 29th Annual Western Conference for the Center for Research in Regulated Industries (CRRI), agenda attached. Mr. Scott Murtishaw, Advisor to Commissioner Picker, was a discussant on the same panel. The attached powerpoint presentation and white paper, which bear on substantive matters addressed in R.15-12-012, were uploaded to the CRRI conference site and available to attendees for download before the conference. They were circulated or presented in connection with SCE's oral remarks, which lasted approximately 20 minutes.

To receive a copy of this *ex parte* notice, please contact:

R. Olivia Samad
2244 Walnut Grove Avenue
Rosemead, CA 91770
olivia.samad@sce.com
Telephone: (626) 302-6008

Respectfully submitted,

FADIA RAFEEDIE KHOURY
R. OLIVIA SAMAD

/S/ R. Olivia Samad
By: R. Olivia Samad

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-3477
Facsimile: (626) 302-7740
E-mail: Olivia.Samad@sce.com

June 23, 2016

Attachment A
AGENDA - 29th Annual Western Conference
for the Center for Research in Regulated Industries (CRRI)

Updated May 16, 2016

Advanced Workshop in Regulation and Competition

29th Annual Western Conference

Hyatt Regency, Monterey, California, on June 22-24, 2016

The Conference features some of the latest developments in the network industries, especially energy, including:

- Deregulation
- Market Structure
- Policy and Regulatory Issues
- Environmental Policy and GHG
- Telecommunications and Water
- Pricing and Demand Response
- Capacity and Reliability

Who should attend:

- Industry Economists, Consultants and Attorneys
- Marketing and Regulatory Managers
- Regulatory Commission Staff

Dinner Speaker: **Robert Kenney**, Vice President, CPUC Regulatory Relations, Pacific Gas and Electric Company

CENTER FOR RESEARCH IN REGULATED INDUSTRIES

RUTGERS

CENTER FOR RESEARCH IN REGULATED INDUSTRIES

The ***Center for Research in Regulated Industries***, located at Rutgers University, aims to further study of regulation in economics, finance, and institutions. Its publications, seminars, workshop, and courses make available the latest advances to academics, managers, and regulatory commission staff. The Center has over thirty five years of experience providing research, instruction, conferences, courses, seminars, and workshops in economics of network industries. The Center's *Journal of Regulatory Economics* is an international scholarly bi-monthly publication intended to provide a forum for the highest quality research in regulatory economics. Other research from the Center's programs has been published in the book series *Topics in Regulatory Economics and Policy*.

crri@business.rutgers.edu
www.business.rutgers.edu/CRRI

Rutgers Business School ● 1 Washington Park, Room 1104 ● Newark, NJ 07102-1897

973-353-5761 ● 973-353-1348 (fax)

Wednesday, June 22, 2016

2:00 - 4:00 Registration *MGB Terrace*

4:00 – 6:00 Welcome to Conference: Victor Glass *PacificRoom*

Rami Kahlon: The California Drought
Carl Danner: Internal Auditing in a Regulatory Agency Context
Tim Brennan: Merger Conditions in Regulated Industries

6:00 - 7:00 Cocktail Hour *MGB Terrace*

7:00 – 9:00 **Dinner & Keynote Speech: Robert Kenney**, Vice President, Pacific Gas and Electric Company *Beach Room*

9:00 – 10:00 Reception *MGB Terrace*

Thursday, June 23, 2016

8:00 - 10:00 ***Concurrent Sessions***

WHOLESALE MARKETS *Grove*

Chair: Eric Korman
Discussants:
Matthew Arenchild: Analyzing Changes in Western Markets: CAISO EIM (Costs, Benefits, and Regulatory Considerations)
Keith Collins: Expanding Electricity Markets through an Energy Imbalance Market
Paul D. Nelson: Opportunities for Energy Market Expansion in the West
KevinWoodruff: Benefits and Costs of "Regional Integration" in the WECC

RETAIL PRICING *Pacific*

Chair: Andre Ramirez
Discussants: Brian Prusnek & Scott Murtishaw
Dennis Keane: The Problem with Current Electric Rate Designs: Making Rates Sustainable
Ahmad Faruqui, Neil Lessem & Dean Mountain: A Three-Year Assessment of the Impact of a Default Deployment of Time-of-Use Rates in Ontario, Canada
Russell Garwacki & Reuben Behlihomji: Time-of-Use Periods for Electric Rates
Katrina Jessoe, David Rapson & Jeremy Smith: Utilization and Customer Behavior: Smart Choices for the Smart Grid

10:00 – 10:20 Coffee Break *MGB Terrace*

10:20 - 11:50 ***Concurrent Sessions***

CAPITAL AND RATE OF RETURN *Grove*

Chair: Carl Peterson
Discussants: Stephen St. Marie
Hung-po Chao & Robert Wilson: Coordination of Electricity Transmission and Generation Investments
Amparo Nieto & Richard Druce: Regulatory Incentive Methods for Electricity Distributors: Emerging Trends
Michael Vilbert, & Joseph B. Wharton: The Impact of Decoupling Ratemaking on the Cost of Capital

PROGRAM MEASUREMENT *Pacific*

Chair: Anne-Marie Cuneo
Discussants:
Reginald Avery Wilkins & Richard Song: Locational Targeting of Energy Efficiency in the PRP Region
Mark Alexander: Measuring the Emissions of Plug-in Electric Vehicles
Neil Lessem: Capturing Smart Meter Benefits in System-Wide Rollouts

11:50 - 1:20 Lunch Break

1:20 - 2:50 ***Concurrent Sessions***

REGULATORY FRAMEWORKS *Grove*

Chair: Bradley Leong
Discussants:
Karl McDermott: Regulatory Lag and the Incentives Question: Fact, Fiction and Myth
Richard White: Valuing Risk Information: A New Tool for Cost-Effective Regulation
Darryl Biggar & Bruce Mountain: The Transactions Cost Approach to Public Utility Regulation and the Role of Customers

RENEWABLES *Pacific*

Chair:
Discussants: Gigio Sakota
Jeff Brown & Ray Williams: Impacts of State GHG Program Design in Implementing EPA's Clean Power Plan
Jiong Gong: Optimal Sizing of Portable Modular Batteries for Electric Vehicles
Aidan Tuohy, Eamonn Lannoye & et.al.: Capacity Adequacy and Variable Generation

2:50 - 3:00 Break

3:00 - 4:00 ***Concurrent Sessions***

RESOURCE INTEGRATION *Grove*

Chair: Gary Stern
Discussants:
Carl Linvill: Teaching the Duck to Fly at Least Cost and with Least Resistance
Gigio Sakota, Tomislav Galjanic, Muir Davis & Raymond Johnson: CAISO Market Integration of Demand Response – Experience and Challenges

POWER MARKET, MARKET POWER *Pacific*

Chair: Charlene Zhou
Discussants:
Megan H. Accordino: Detecting Manipulation of Related Spot and Futures Markets
Hjalmar Pihl: Natural Gas Price Volatility at Western Trading Hubs

FRIDAY, JUNE 24, 2016

8:30 - 10:30 *Concurrent Sessions*

METHODOLOGY

Chair:
Discussants:
Josephine Duh & Ahmad Faruqui: Emerging Issues in Forecasting Energy Consumption, Peak, and Hourly Load
Amin Fakhrazari & Amitava Dhar: A Stochastic Approach To Quantify Load Diversity Factors on Distribution Circuits
Aberto Lamadrid, , W. Jeon, H. Lu and Tim Mount: Using a Receding-Horizon Optimization to Manage Renewable Generation Efficiently II
Brian Lubeck: Using a Gaussian Copula within a Monte Carlo Simulation Framework to Model Load Uncertainty

DISTRIBUTED GENERATION & STORAGE *Pacific*

Chair: Nguyen Quan
Discussants: Andrew Dugowson
Rasika Athawale: Small to Big, and Again Small: Will Distributed Generation Achieve Success?
David Brown & David Sappington: Optimal Policies to Promote Efficient Distributed Generation of Electricity
Cynthia Fang & Josh Mondragon: Solar Adoption and Customer Demand in the Residential Sector
Udi Helman et al: Economic Benefits of Energy Storage under California's Storage Mandate: Assessment of Different Storage Attributes and Applications under 33% and 40% RPS Scenarios

10:30 – 11:00 Coffee Break *MGB Terrace*

11:00 - 12:30 *Concurrent Sessions*

OPERATIONAL CONSIDERATIONS *Grove*

Chair: Brittney Lee
Discussants:
Lamine Akaba & Christine Hartmann: Machine Learning, Performance Predictors, and Demand Response
Robert Entriken, et al: Operating Reserve Determination: Test Cases and Market Design Insights
John Ledyard & Karl McDermott: The Behavior of Public Utilities in the Face of Demand Uncertainty, Costly Adjustments and Prudence Reviews

WATER *Pacific*

Chair: Stanley Lee
Discussants: Eric Korman & Viet Truong
Michael Crew & Rami Kahlon: Franchising Revisited: Developments in the Water Sector
Richard McCann, Edward Spang & Frank Loge: Using Water Utility Systems to Better Integrate Distributed Energy Resources
Bob Kelly: A Brief History Of The California WRAM

12:30- 12:35 Concluding Remarks – Victor Glass

SPEAKERS DISCUSSANTS & CHAIRS

Megan H. Accordino, Associate, Analysis Group, Inc.
Lamine Akaba, Principal, Pacific Gas and Electric Company
Mark Alexander, EPRI
Matthew Arenchild, Managing Director – Energy, Navigant
Rasika Athawale, Research Manager. Rutgers University
Reuben Behlihomji, Southern California Edison
Darryl Biggar, Australian Competition and Consumer Commission
Tim Brennan, University of Maryland Baltimore County
David Brown, Assistant Professor, University of Alberta
Jeff Brown, Principal Long Term Energy Policy, PG&E
Hung-po Chao, President, Energy Trading Analytic
Keith Collins, Manager, Monitoring and Reporting, California ISO
Michael A. Crew, Professor of Regulatory Economics, Rutgers University
Anne-Marie Cuneo, Direcdtor of Regulatory Operations. Public Utilities Commission of Nevada
Carl Danner, Chief Internal Auditor, California Public Utilities Commission
Andrew Dugowson, Energy & Environmental Policy, Southern California Edison
Josephine Duh, Associate, The Brattle Group
Robert Entriken, Principal Technical Leader, EPRI
Amin Fakhrazari, Regulatory Affairs, Pacific Gas and Electric Company
Cynthia Fang, Rate Strategy and Analysis Manager, San Diego Gas & Electric
Ahmad Faruqui, Principal, The Brattle Group
Russell Garwacki, Director –Pricing Design and Research, Southern California Edison
Victor Glass, Director CRRI and Professor of Professional Practice, Rutgers University
Jiong Gong, Henan University
Christine Hartmann, Analyst, Pacific Gas and Electric Company
Udi Helman, Consultant
Katrina Jessoe, Assistant Professor, UC Davis
Rami Kahlon, Director of the Water Division, California Public Utilities Commission
Dennis Keane, Senior Manager, Rate Design and Quantitative Analysis, Pacific Gas and Electric Company
Bob Kelly, Vice President Regulatory Affairs,Suburban Water Systems
Robert Kenney, Vice President, CPUC Regulatory Relations, Pacific Gas and Electric Company
Eric Korman, Vice President, Analysis Group, Inc.
Alberto Lamadrid, Lehigh University
John O. Ledyard, Allen and Lenabelle Davis Professor of Economics and Social Sciences, California Institute of Technology
Brittney Lee, Regulatory Case Administrator, San Diego Gas & Electric
Stanley Lee, California Public Utilities Commission
Bradley Leong, California Public Utilities Commission
Neil Lessem, Consultant, The Brattle Group
Carl Linvill, Principal, The Regulatory Assistance Project
Brian Lubeck, Regulatory Affairs, Pacific Gas and Electric Company
Richard McCann, Partner, M.Cubed
Karl A. McDermott, Ameren Professor of Government and Business, University of Illinois-Springfield & Special Consultant, NERA Economic Consulting
Timothy D. Mount, Professor, Cornell University
Scott Murtishaw, Advisor, California Public Utilities Commission
Paul D. Nelson, Market Design Manager, Southern California Edison
Amparo Nieto, Vice President, NERA Economic Consulting
Carl R. Peterson, Professor, University of Illinois Springfield
Hjalmar Pihl, California ISO
Brian Prusnek, Director of Regulatory Affairs, Sempra Energy Utilities
Nguyen Quan, Manager Regulatory Affairs, Golden State Water Company
Andre Ramirez, Regulatory Affairs, Southern California Edison
Gigio Sakota, Senior Project Manager, Southern California Edison
Carl Silsbee, Regulatory Economist
Richard Song, Lead Analyst, Southern California Edison
Gary Stern, Director of Energy Policy, Southern California Edison
Stephen St. Marie, Policy Planning Analyst, California Public Utilities Commission
Viet Truong, Utilities Engineer, California Public Utilities Commission
Aidan Tuohy, EPRI
Michael J. Vilbert, Principal, The Brattle Group
Richard White, Senior Policy Analyst, California Public Utilities Commission
Reginald Avery Wilkins, Project Manager, Southern California Edison
Kevin Woodruff, Principal, Woodruff Expert Services
Charlene Zhou, Manager, Analysis Group, Inc.

ORGANIZING COMMITTEE

Matthew Arenchild (Navigant Consulting, Inc.)
Michael A. Crew (Rutgers University)
Carl Danner (California Public Utilities Commission)
Robert Earle
Robert Entriken (EPRI)
Cynthia Fang (San Diego Gas & Electric)
Ahmad Faruqui (Brattle Group)
Victor Glass (Rutgers University)
Rami Kahlon (California Public Utilities Commission)
Dennis Keane (Pacific Gas & Electric)
Neil Lessem (The Brattle Group)
Carl B. Linvill (The Regulatory Assistance Project)
Paul Nelson (Southern California Edison)
Amparo Nieto (NERA Economic Consulting)
Kevin D. Woodruff (Woodruff Expert Services)

CONTACTING CRRI

Victor Glass, Director – CRRI and Professor of Professional Practice, Rutgers University

Home Page: www.business.rutgers.edu/CRRI

Address: Center for Research in Regulated Industries
Rutgers Business School, Rutgers University,
1 Washington Park, Room 1120
Newark, NJ 07102-1897

Phone: 973-353-5761
Fax: 973-353-1348
Email: vglass@business.rutgers.edu (Victor Glass)
crri@business.rutgers.edu (CRRI Admin Asst)

HOTEL RESERVATIONS

Sufficient Rooms are reserved at the Hyatt Regency Monterey for all of the Conference participants. Reservations should be received by **June 2, 2016**. Hotel reservation can be made by using the following Passkey Link:

https://resweb.passkey.com/go/CRRIannualConf2016

Hyatt Regency Monterey

1 Golf Course Road
Monterey, California, 93940, USA
1-888-421-1442

If you are not making reservations through the link above please identify yourself as being held under the group block: Rutgers University CRRI Program.

REGISTRATION INFORMATION

To Register: Please complete and return the form to CRRI. Registrations are accepted by mail, email, fax, and telephone. Please confirm telephone registrations by sending in a completed and signed registration form. The deadline for registrations is May 16, 2016. Registrations received after May 16, 2016 will be admitted on a space available basis.

Volume discount: Second and subsequent applications received in the same envelope, fax, email, or made at the same time by phone will receive a 5% volume discount.

Payment Information: Make checks payable to **"Rutgers University"** and mail to the attention of at the above address. Fees include prescribed learning materials, dinner on Wednesday night, June 22, 2016, all receptions and coffee breaks, but do not include lodging and other meals. The government registration fee is available for government employees.

REGISTRATION FORM: 29th Annual Western Conference

Name

Title:

Company:

Complete Address:

Telephone: Fax:

Email:

Billing Information:

___ Payment enclosed $1,135 U.S. Dollars

___ Send invoice to participant at above address.

___ Send invoice to___________________________

___ Credit Card: ___ VISA ___ MC Exp. ____/____ CVC Code:____ Card #____

GOVERNMENT RATE: Government employees may apply for reduced enrollment fees.

____I would like to apply for the govt rate of $610

CANCELLATION POLICY: Until May 2, 2016 cancellation is allowed without penalty and refunds will be allowed in full. After this date, the indicated fee is due in full whether or not the participant actually attends. Substitutions may be made at any time.

Signature of Participant: ____

Attachment B

Time Differentiated Distribution Costs & TOU Period Determination (Power Point)

Time Differentiated Distribution Costs & TOU Period Determination

29th Annual Western Conference – Monterey, California

June 22-24, 2016

Reuben.Behlihomji@sce.com

Manager, Marginal Cost

Overview

When determining future Time-of-Use (TOU) periods in electricity pricing, should distribution costs be added to the equation?

- Forward Looking
- Generation Marginal Costs
  - TOU periods based on time variant allocation of Capacity and Energy marginal costs
- Evolving Landscape
  - 50% Renewable Portfolio Standard (RPS) mandates: Driving system level CAISO operating constraints
  - Advances in technology and customer adoption of Distributed Energy Resources (DER): Driving distribution level IOU operating constraints

Why Distribution Marginal Costs Matter?

- Largest component of capital expenditures for SCE (60%)
- Distribution revenues account for 40% of SCE's overall revenue requirement

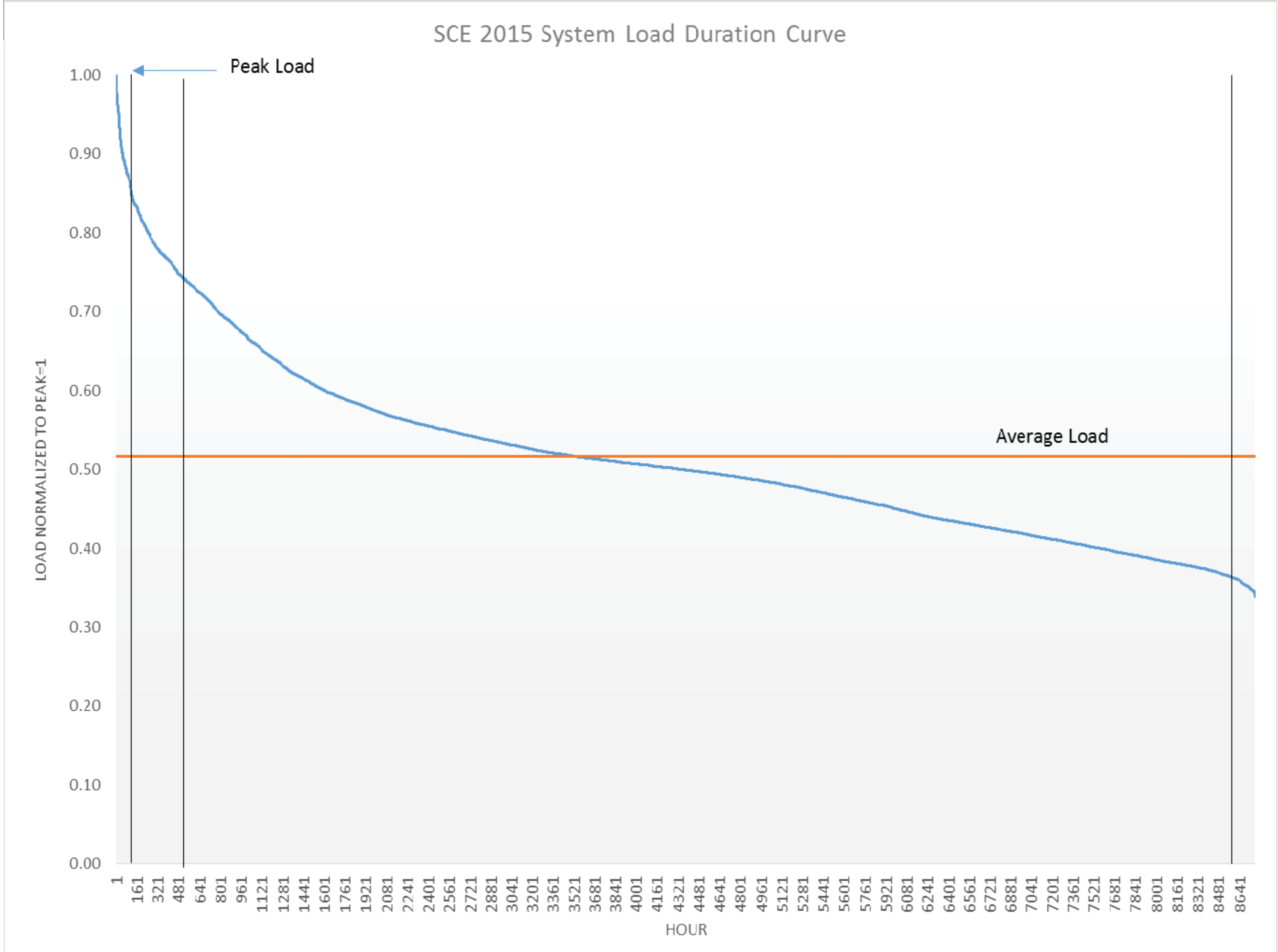
Conceptual Framework of Distribution as a Cost Driver

	Traditional	Prospective
Valuation	Capacity – Peak driven need	Capacity – Peak driven need Grid – Energy transfer
Allocation	Capacity – Effective Demand Factor (EDF) *	Capacity – Time Variant Grid – Non time Variant
Rate Design Recovery	Non Time Differentiated Demand Charges	Capacity – Time variant Peak Demand Grid – Average Demand

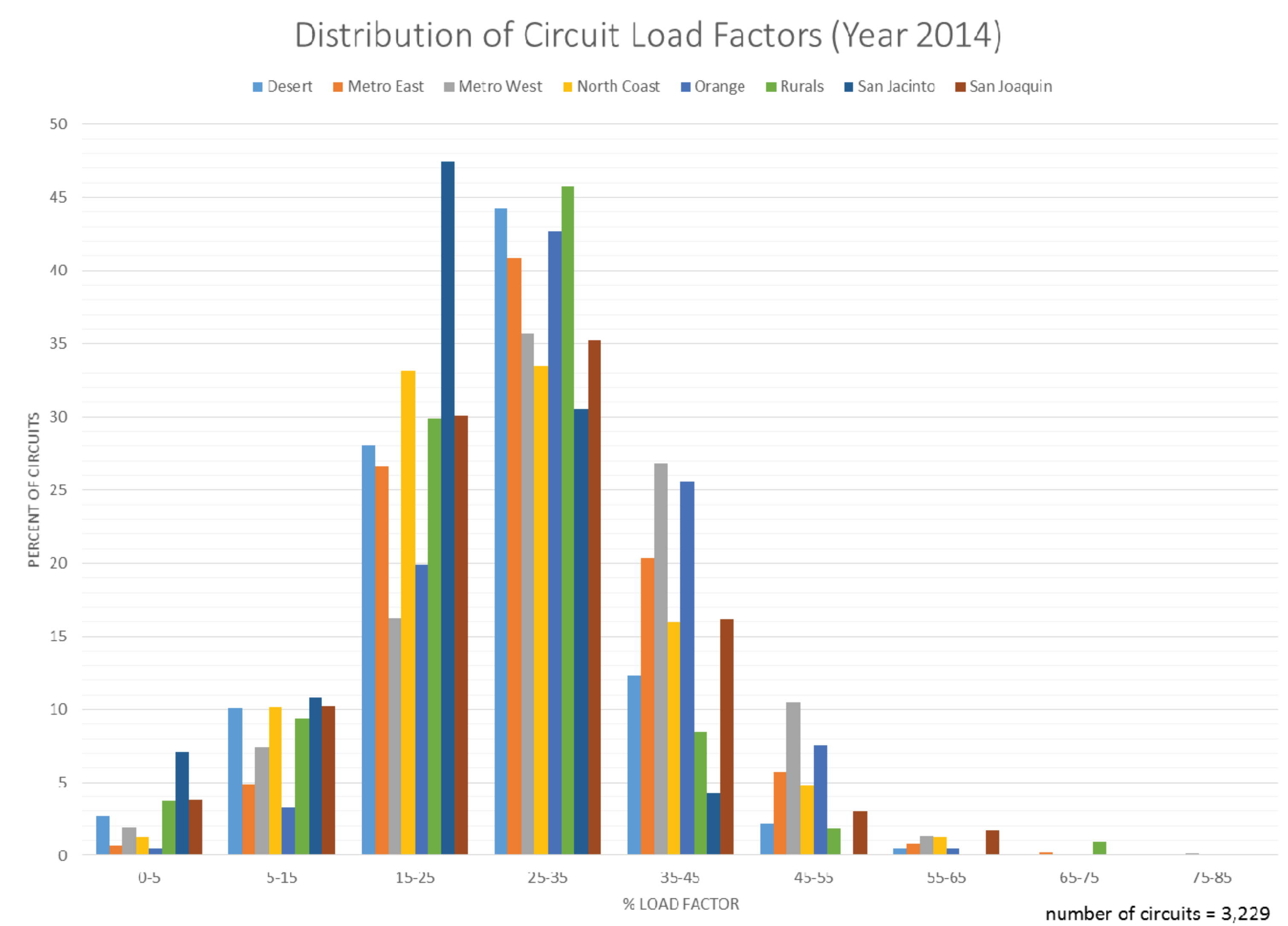
* EDF: The ratio of a rate group's contribution to the circuit peak load to the customer's annual non-coincident peak demand.

It’s a Matter of “Time”

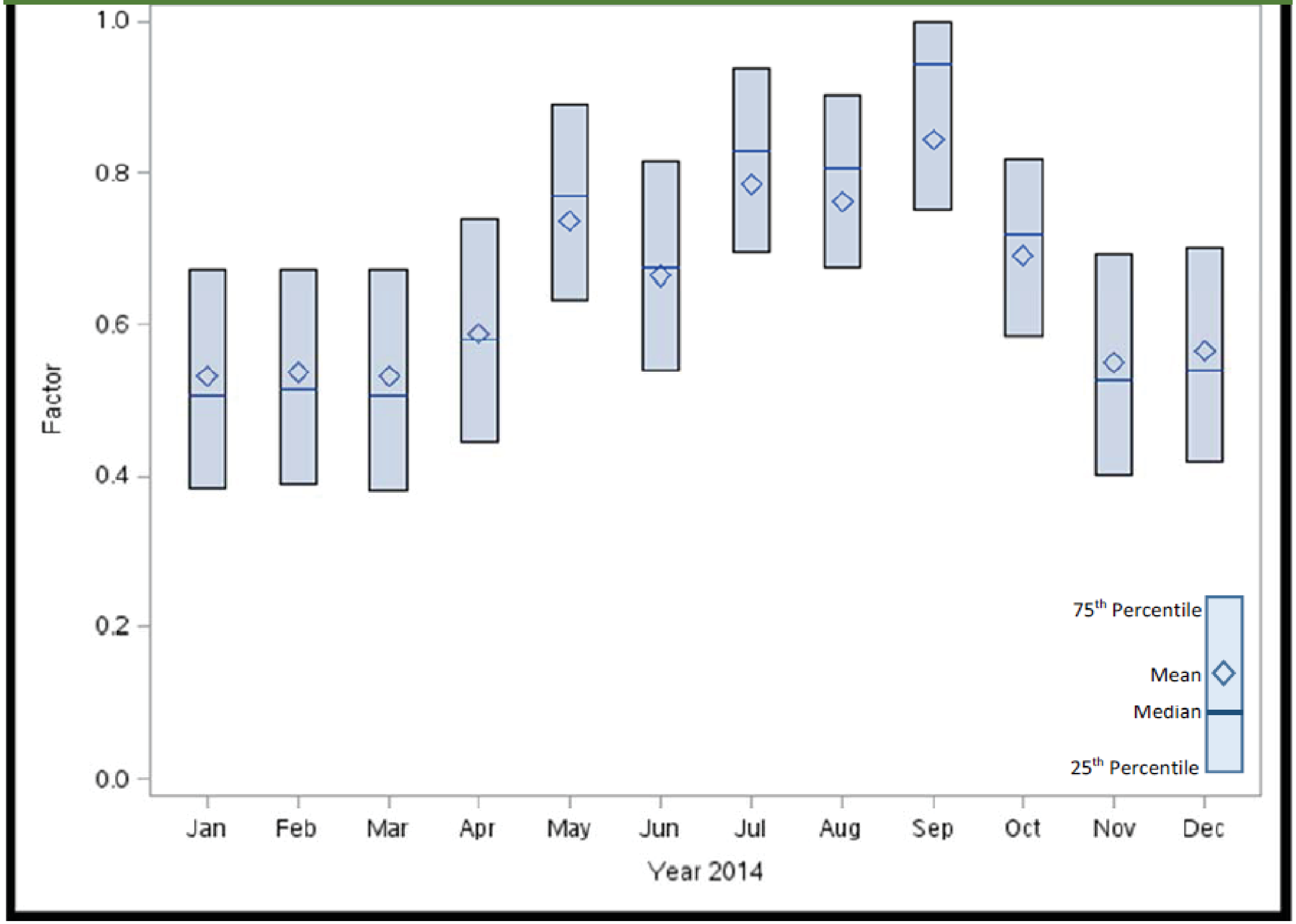
Historically, load duration curves help determine proportionate usage between peak needs and average demand needs



SCE's typical circuit load factors are between 20% to 40%



Analysis of load factor by month demonstrates a strong correlation between monthly peaks to the annual peak



Drawing the Line – Peak Needs vs. Grid Needs

- Valuation: Split between peak and non-peak marginal costs

Valuation Methods	Non-Peak *	Peak *
NERA/FERC Approach	82%	18%
NERA/FERC (Circuit Miles)	52%	48%
Minimum Cost Method	60%	40%
Capacity Utilization	80%	20%
Long- vs. Short-run	-	100%

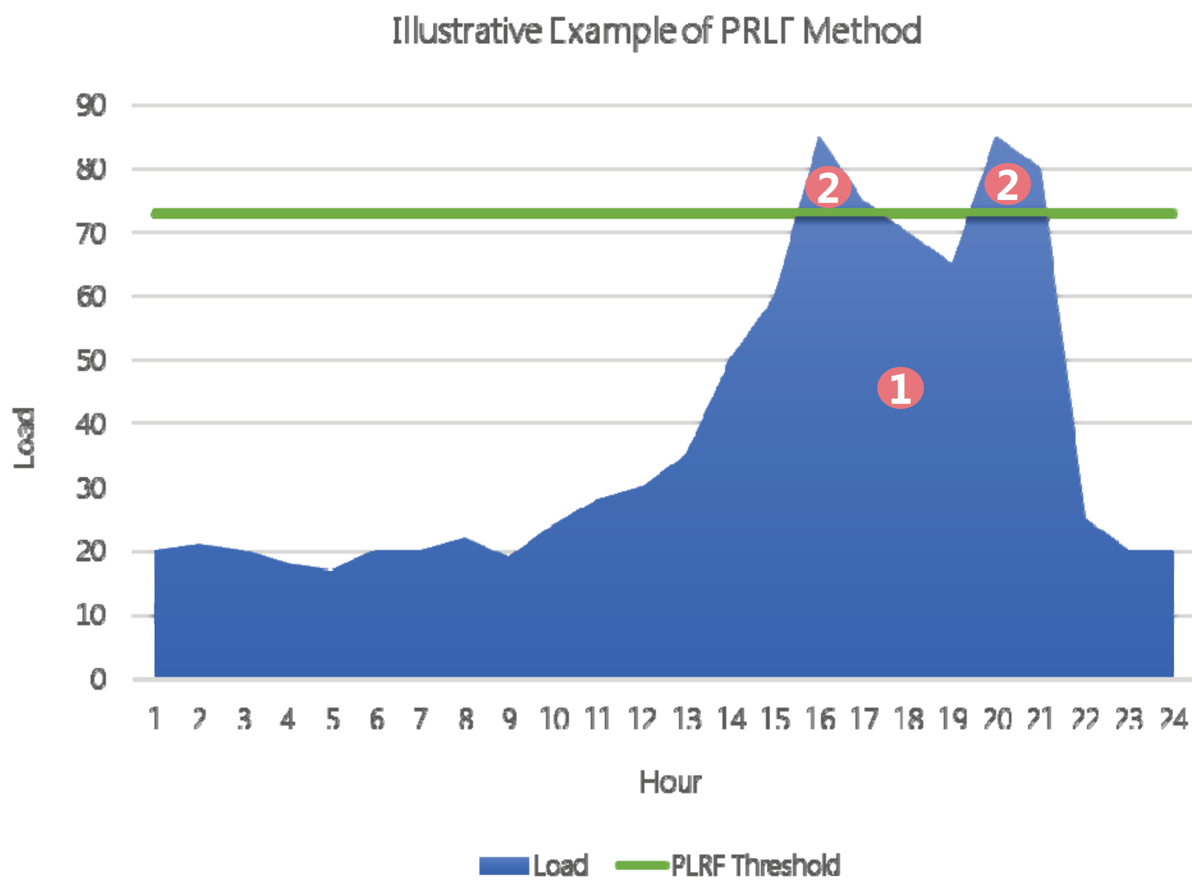
* Preliminary numbers, pending updates

- Allocation: Peak driven marginal costs would be the only time variant component of distribution costs

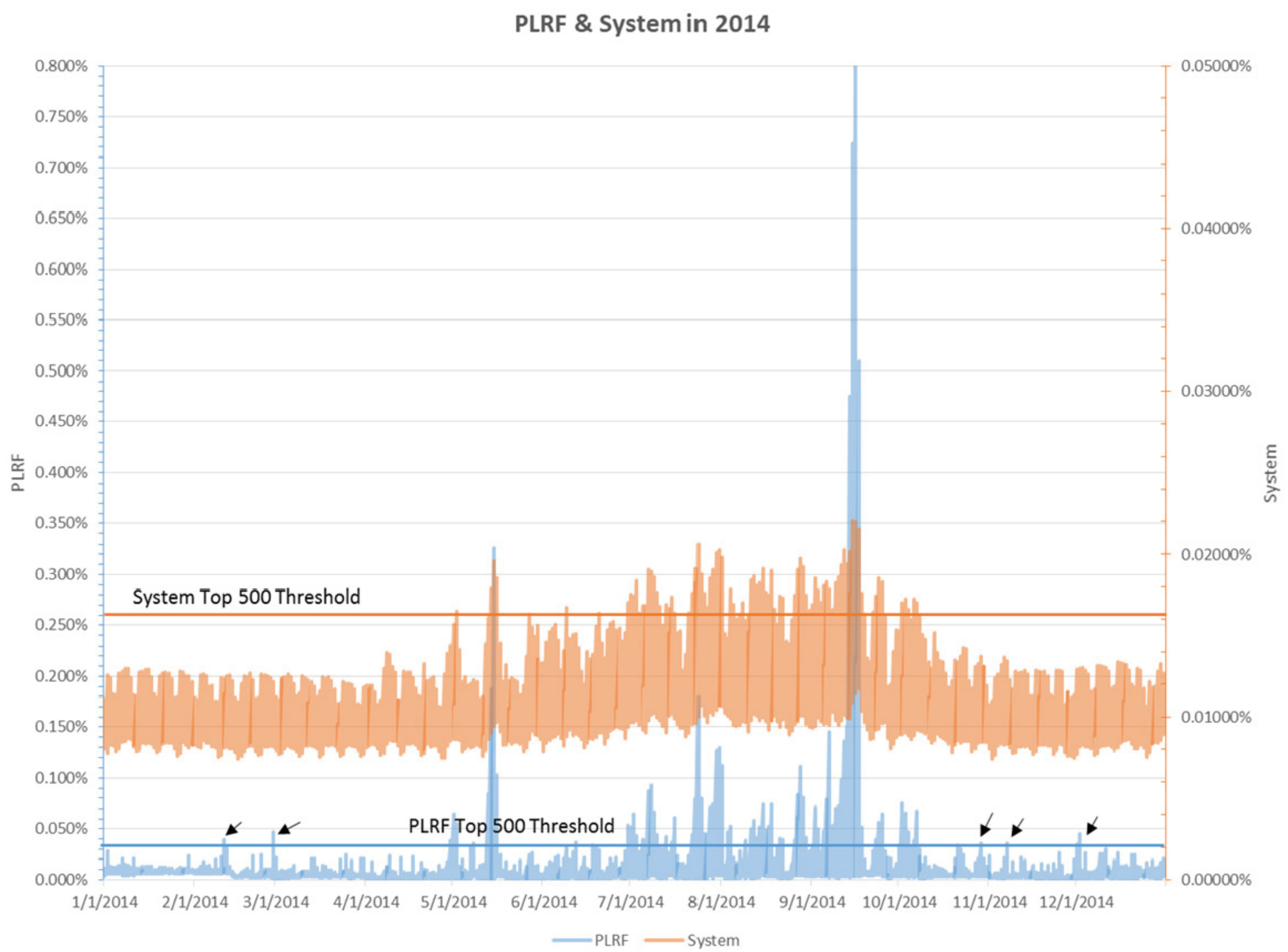
	Generation	Distribution
Peak	Loss of Load Expectations (LOLE)	Peak Load Risk Factor (PLRF)
Non-Peak	Energy (kWh)	Average Demand (kW) or Energy (kWh)
Connection	n/a	No. of Customers

Peak Load Risk Factor (PLRF) Method

- The PLRF analysis is conducted using a two-step approach
  1. Circuit load points below 73 percent of average circuit Planned Loading Limit (PLL) are set to zero
  2. Remaining peak load points are aggregated by hour for each circuit



Importance of Diversity



Forward-looking PLRF by circuit for 2014 and 2024

2014 Recorded PLRF Load Standardized Variable Heat Map

Average of SV PLRF — Column

Row Labels	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
WEEKDAYS	**(0.38)**	**(0.38)**	**(0.40)**	**(0.40)**	**(0.38)**	**(0.32)**	**(0.19)**	**(0.04)**	**0.10**	**0.28**	**0.41**	**0.51**	**0.71**	**0.82**	**0.86**	**0.76**	**0.55**	**0.39**	**0.30**	**0.22**	**0.03**	**(0.19)**	**(0.30)**	**(0.34)**
JAN	(0.36)	(0.36)	(0.36)	(0.38)	(0.38)	(0.37)	(0.32)	(0.22)	(0.15)	(0.10)	(0.08)	(0.08)	(0.10)	(0.05)	(0.11)	(0.17)	(0.22)	(0.12)	(0.09)	(0.14)	(0.18)	(0.26)	(0.32)	(0.34)
FEB	(0.40)	(0.40)	(0.42)	(0.42)	(0.42)	(0.39)	(0.33)	(0.23)	(0.14)	(0.11)	(0.07)	(0.05)	(0.06)	(0.07)	(0.12)	(0.16)	(0.26)	(0.18)	(0.09)	(0.12)	(0.18)	(0.27)	(0.35)	(0.37)
MAR	(0.44)	(0.44)	(0.46)	(0.45)	(0.43)	(0.35)	(0.26)	(0.17)	(0.12)	(0.05)	(0.04)	(0.01)	0.01	(0.05)	(0.12)	(0.20)	(0.31)	(0.28)	(0.14)	(0.16)	(0.23)	(0.32)	(0.38)	(0.40)
APR	(0.41)	(0.41)	(0.44)	(0.44)	(0.41)	(0.38)	(0.25)	(0.15)	(0.06)	0.01	0.08	0.09	0.16	0.12	0.09	(0.02)	(0.17)	(0.24)	(0.12)	(0.12)	(0.22)	(0.31)	(0.36)	(0.39)
MAY	(0.41)	(0.42)	(0.43)	(0.42)	(0.38)	(0.33)	(0.09)	0.11	0.31	0.58	0.75	0.92	1.18	1.32	1.40	1.31	1.04	0.68	0.43	0.43	0.19	(0.13)	(0.31)	(0.37)
JUN	(0.36)	(0.36)	(0.36)	(0.35)	(0.33)	(0.24)	(0.08)	0.05	0.14	0.35	0.41	0.43	0.58	0.64	0.66	0.53	0.31	0.15	0.07	0.11	0.04	(0.11)	(0.22)	(0.31)
JUL	(0.31)	(0.31)	(0.34)	(0.32)	(0.28)	(0.20)	0.01	0.22	0.47	0.82	1.07	1.35	1.82	2.34	2.54	2.57	2.18	1.58	0.90	0.67	0.43	0.03	(0.17)	(0.25)
AUG	(0.32)	(0.32)	(0.34)	(0.35)	(0.31)	(0.23)	(0.04)	0.17	0.41	0.72	0.91	1.10	1.50	1.72	1.95	1.79	1.38	0.81	0.44	0.44	0.14	(0.14)	(0.22)	(0.28)
SEP	(0.34)	(0.35)	(0.38)	(0.38)	(0.34)	(0.24)	(0.04)	0.25	0.61	1.10	1.58	2.10	2.85	3.34	3.51	3.28	2.69	1.98	1.94	1.60	0.80	0.06	(0.22)	(0.31)
OCT	(0.38)	(0.39)	(0.41)	(0.39)	(0.38)	(0.27)	(0.16)	(0.05)	0.06	0.22	0.36	0.42	0.61	0.59	0.54	0.36	0.15	0.20	0.20	0.08	(0.13)	(0.27)	(0.33)	(0.36)
NOV	(0.38)	(0.39)	(0.39)	(0.40)	(0.41)	(0.39)	(0.33)	(0.21)	(0.13)	(0.07)	(0.04)	(0.01)	0.01	0.04	0.02	(0.08)	(0.12)	(0.04)	(0.06)	(0.15)	(0.23)	(0.27)	(0.33)	(0.34)
DEC	(0.42)	(0.43)	(0.43)	(0.46)	(0.45)	(0.43)	(0.37)	(0.31)	(0.23)	(0.17)	(0.14)	(0.15)	(0.19)	(0.17)	(0.20)	(0.24)	(0.19)	0.02	0.06	(0.01)	(0.10)	(0.24)	(0.35)	(0.38)
WEEKENDS	**(0.37)**	**(0.38)**	**(0.40)**	**(0.42)**	**(0.42)**	**(0.42)**	**(0.41)**	**(0.40)**	**(0.39)**	**(0.37)**	**(0.33)**	**(0.27)**	**(0.15)**	**(0.03)**	**0.09**	**0.13**	**0.08**	**(0.01)**	**(0.07)**	**(0.12)**	**(0.21)**	**(0.34)**	**(0.37)**	**(0.39)**
JAN	(0.35)	(0.35)	(0.35)	(0.37)	(0.38)	(0.38)	(0.39)	(0.38)	(0.36)	(0.35)	(0.34)	(0.35)	(0.37)	(0.35)	(0.35)	(0.35)	(0.34)	(0.27)	(0.24)	(0.25)	(0.28)	(0.32)	(0.35)	(0.37)
FEB	(0.41)	(0.42)	(0.42)	(0.43)	(0.43)	(0.43)	(0.43)	(0.42)	(0.40)	(0.39)	(0.42)	(0.41)	(0.41)	(0.42)	(0.43)	(0.42)	(0.42)	(0.36)	(0.31)	(0.30)	(0.34)	(0.36)	(0.41)	(0.42)
MAR	(0.43)	(0.43)	(0.45)	(0.46)	(0.45)	(0.44)	(0.43)	(0.44)	(0.44)	(0.44)	(0.44)	(0.43)	(0.43)	(0.43)	(0.44)	(0.45)	(0.44)	(0.41)	(0.33)	(0.34)	(0.37)	(0.42)	(0.43)	(0.44)
APR	(0.40)	(0.39)	(0.42)	(0.44)	(0.44)	(0.43)	(0.40)	(0.40)	(0.39)	(0.39)	(0.39)	(0.40)	(0.40)	(0.42)	(0.42)	(0.43)	(0.45)	(0.42)	(0.34)	(0.35)	(0.35)	(0.35)	(0.39)	(0.41)
MAY	(0.37)	(0.40)	(0.41)	(0.42)	(0.42)	(0.43)	(0.41)	(0.40)	(0.37)	(0.38)	(0.34)	(0.32)	(0.28)	(0.24)	(0.20)	(0.20)	(0.20)	(0.25)	(0.25)	(0.20)	(0.26)	(0.35)	(0.38)	(0.40)
JUN	(0.36)	(0.37)	(0.40)	(0.41)	(0.40)	(0.40)	(0.39)	(0.42)	(0.43)	(0.40)	(0.38)	(0.34)	(0.28)	(0.20)	(0.14)	(0.10)	(0.11)	(0.13)	(0.16)	(0.16)	(0.20)	(0.28)	(0.35)	(0.37)
JUL	(0.33)	(0.34)	(0.37)	(0.38)	(0.38)	(0.37)	(0.35)	(0.38)	(0.39)	(0.34)	(0.25)	(0.08)	0.14	0.42	0.74	0.90	0.84	0.58	0.26	0.09	0.01	(0.20)	(0.33)	(0.35)
AUG	(0.35)	(0.38)	(0.41)	(0.43)	(0.44)	(0.42)	(0.41)	(0.40)	(0.39)	(0.37)	(0.31)	(0.22)	(0.01)	0.26	0.53	0.66	0.52	0.23	0.00	(0.00)	(0.13)	(0.24)	(0.31)	(0.35)
SEP	(0.35)	(0.37)	(0.41)	(0.42)	(0.42)	(0.43)	(0.43)	(0.41)	(0.41)	(0.31)	(0.06)	0.42	1.28	2.04	2.64	2.84	2.45	1.58	1.11	0.83	0.31	(0.17)	(0.33)	(0.37)
OCT	(0.37)	(0.38)	(0.40)	(0.41)	(0.41)	(0.42)	(0.40)	(0.36)	(0.36)	(0.34)	(0.34)	(0.35)	(0.28)	(0.12)	0.01	0.02	(0.07)	(0.05)	(0.04)	(0.14)	(0.23)	(0.34)	(0.36)	(0.39)
NOV	(0.35)	(0.36)	(0.37)	(0.40)	(0.40)	(0.41)	(0.41)	(0.38)	(0.35)	(0.34)	(0.32)	(0.33)	(0.35)	(0.35)	(0.35)	(0.36)	(0.35)	(0.32)	(0.30)	(0.33)	(0.36)	(0.39)	(0.41)	(0.40)
DEC	(0.43)	(0.43)	(0.43)	(0.44)	(0.45)	(0.44)	(0.45)	(0.42)	(0.39)	(0.38)	(0.38)	(0.38)	(0.41)	(0.40)	(0.42)	(0.41)	(0.37)	(0.21)	(0.17)	(0.20)	(0.25)	(0.31)	(0.41)	(0.41)
Grand Total	**(0.38)**	**(0.38)**	**(0.40)**	**(0.40)**	**(0.39)**	**(0.35)**	**(0.25)**	**(0.15)**	**(0.05)**	**0.08**	**0.18**	**0.28**	**0.44**	**0.56**	**0.62**	**0.57**	**0.41**	**0.27**	**0.19**	**0.12**	**(0.04)**	**(0.22)**	**(0.32)**	**(0.36)**

2024 Recorded PLRF Load Standardized Variable Heat Map

Average of SV PLRF — Column

Row Labels	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
WEEKDAYS	**(0.41)**	**(0.41)**	**(0.43)**	**(0.43)**	**(0.40)**	**(0.33)**	**(0.17)**	**(0.02)**	**0.12**	**0.28**	**0.38**	**0.45**	**0.61**	**0.68**	**0.72**	**0.67**	**0.58**	**0.60**	**0.57**	**0.47**	**0.18**	**(0.13)**	**(0.30)**	**(0.36)**
JAN	(0.39)	(0.39)	(0.39)	(0.41)	(0.41)	(0.40)	(0.33)	(0.21)	(0.13)	(0.10)	(0.09)	(0.09)	(0.12)	(0.07)	(0.13)	(0.18)	(0.22)	(0.00)	0.02	(0.08)	(0.17)	(0.26)	(0.34)	(0.37)
FEB	(0.43)	(0.43)	(0.45)	(0.46)	(0.45)	(0.42)	(0.34)	(0.22)	(0.13)	(0.12)	(0.07)	(0.07)	(0.08)	(0.07)	(0.10)	(0.17)	(0.27)	(0.13)	(0.00)	(0.07)	(0.16)	(0.28)	(0.37)	(0.41)
MAR	(0.47)	(0.48)	(0.50)	(0.49)	(0.46)	(0.37)	(0.26)	(0.16)	(0.11)	(0.07)	(0.07)	(0.05)	(0.02)	(0.08)	(0.14)	(0.23)	(0.33)	(0.27)	(0.07)	(0.11)	(0.21)	(0.32)	(0.41)	(0.44)
APR	(0.44)	(0.44)	(0.48)	(0.48)	(0.45)	(0.40)	(0.25)	(0.14)	(0.07)	(0.01)	0.05	0.06	0.13	0.10	0.08	(0.03)	(0.17)	(0.22)	(0.05)	(0.03)	(0.18)	(0.31)	(0.38)	(0.42)
MAY	(0.45)	(0.46)	(0.47)	(0.46)	(0.41)	(0.34)	(0.06)	0.13	0.33	0.58	0.70	0.83	1.05	1.15	1.24	1.20	1.04	0.84	0.65	0.69	0.36	(0.05)	(0.31)	(0.39)
JUN	(0.39)	(0.39)	(0.38)	(0.38)	(0.35)	(0.23)	(0.05)	0.08	0.16	0.35	0.41	0.40	0.53	0.57	0.60	0.47	0.32	0.27	0.21	0.28	0.16	(0.07)	(0.21)	(0.32)
JUL	(0.32)	(0.33)	(0.36)	(0.34)	(0.30)	(0.18)	0.06	0.26	0.50	0.82	1.01	1.21	1.54	1.83	2.05	2.16	2.12	2.03	1.61	1.31	0.89	0.23	(0.12)	(0.24)
AUG	(0.33)	(0.33)	(0.35)	(0.36)	(0.31)	(0.21)	0.03	0.23	0.47	0.76	0.89	1.01	1.32	1.46	1.63	1.61	1.47	1.21	0.97	0.93	0.47	(0.04)	(0.21)	(0.27)
SEP	(0.36)	(0.38)	(0.41)	(0.41)	(0.36)	(0.23)	(0.01)	0.31	0.67	1.12	1.48	1.86	2.46	2.82	3.01	3.07	2.92	2.74	2.81	2.40	1.29	0.24	(0.19)	(0.32)
OCT	(0.41)	(0.42)	(0.44)	(0.43)	(0.40)	(0.28)	(0.15)	(0.01)	0.08	0.24	0.37	0.41	0.59	0.57	0.52	0.39	0.22	0.39	0.38	0.19	(0.09)	(0.28)	(0.35)	(0.39)
NOV	(0.41)	(0.42)	(0.43)	(0.44)	(0.45)	(0.42)	(0.36)	(0.22)	(0.13)	(0.07)	(0.04)	(0.02)	0.01	0.04	0.04	(0.06)	(0.10)	0.07	0.04	(0.12)	(0.23)	(0.28)	(0.36)	(0.37)
DEC	(0.46)	(0.46)	(0.47)	(0.50)	(0.49)	(0.47)	(0.39)	(0.33)	(0.24)	(0.19)	(0.16)	(0.18)	(0.23)	(0.20)	(0.22)	(0.26)	(0.18)	0.18	0.21	0.12	(0.02)	(0.22)	(0.36)	(0.41)
WEEKENDS	**(0.40)**	**(0.41)**	**(0.44)**	**(0.45)**	**(0.45)**	**(0.45)**	**(0.44)**	**(0.43)**	**(0.42)**	**(0.40)**	**(0.38)**	**(0.34)**	**(0.28)**	**(0.19)**	**(0.10)**	**(0.02)**	**0.05**	**0.11**	**0.08**	**0.01**	**(0.13)**	**(0.30)**	**(0.39)**	**(0.42)**
JAN	(0.38)	(0.38)	(0.39)	(0.41)	(0.41)	(0.42)	(0.42)	(0.42)	(0.39)	(0.38)	(0.38)	(0.38)	(0.40)	(0.39)	(0.38)	(0.39)	(0.37)	(0.27)	(0.23)	(0.25)	(0.30)	(0.34)	(0.38)	(0.40)
FEB	(0.45)	(0.46)	(0.46)	(0.47)	(0.47)	(0.47)	(0.46)	(0.46)	(0.43)	(0.43)	(0.46)	(0.44)	(0.45)	(0.46)	(0.46)	(0.45)	(0.45)	(0.37)	(0.31)	(0.31)	(0.35)	(0.38)	(0.45)	(0.45)
MAR	(0.46)	(0.47)	(0.49)	(0.50)	(0.49)	(0.48)	(0.47)	(0.48)	(0.48)	(0.48)	(0.49)	(0.47)	(0.48)	(0.47)	(0.48)	(0.48)	(0.48)	(0.45)	(0.33)	(0.33)	(0.38)	(0.43)	(0.46)	(0.48)
APR	(0.43)	(0.43)	(0.45)	(0.47)	(0.48)	(0.46)	(0.44)	(0.44)	(0.42)	(0.43)	(0.43)	(0.45)	(0.45)	(0.47)	(0.46)	(0.47)	(0.49)	(0.45)	(0.35)	(0.38)	(0.38)	(0.38)	(0.43)	(0.44)
MAY	(0.40)	(0.43)	(0.44)	(0.46)	(0.46)	(0.46)	(0.44)	(0.44)	(0.40)	(0.41)	(0.38)	(0.37)	(0.33)	(0.30)	(0.26)	(0.25)	(0.23)	(0.22)	(0.21)	(0.14)	(0.22)	(0.36)	(0.41)	(0.44)
JUN	(0.39)	(0.40)	(0.43)	(0.44)	(0.43)	(0.43)	(0.42)	(0.45)	(0.47)	(0.44)	(0.43)	(0.39)	(0.34)	(0.29)	(0.24)	(0.21)	(0.14)	(0.07)	(0.07)	(0.02)	(0.10)	(0.25)	(0.35)	(0.39)
JUL	(0.35)	(0.36)	(0.40)	(0.42)	(0.41)	(0.40)	(0.38)	(0.41)	(0.43)	(0.38)	(0.31)	(0.22)	(0.08)	0.08	0.28	0.52	0.70	0.78	0.71	0.50	0.28	(0.08)	(0.30)	(0.35)
AUG	(0.36)	(0.39)	(0.43)	(0.46)	(0.46)	(0.44)	(0.43)	(0.42)	(0.42)	(0.39)	(0.34)	(0.28)	(0.14)	0.01	0.20	0.40	0.47	0.54	0.35	0.30	0.06	(0.18)	(0.29)	(0.35)
SEP	(0.38)	(0.40)	(0.44)	(0.46)	(0.46)	(0.46)	(0.46)	(0.45)	(0.44)	(0.36)	(0.17)	0.10	0.57	1.07	1.58	2.10	2.48	2.31	1.89	1.45	0.65	(0.07)	(0.32)	(0.40)
OCT	(0.40)	(0.41)	(0.44)	(0.44)	(0.45)	(0.45)	(0.43)	(0.38)	(0.39)	(0.36)	(0.37)	(0.39)	(0.33)	(0.19)	(0.09)	(0.06)	(0.03)	0.10	0.08	(0.09)	(0.20)	(0.36)	(0.39)	(0.42)
NOV	(0.38)	(0.39)	(0.40)	(0.43)	(0.44)	(0.45)	(0.44)	(0.41)	(0.39)	(0.37)	(0.35)	(0.36)	(0.39)	(0.38)	(0.38)	(0.39)	(0.38)	(0.31)	(0.30)	(0.35)	(0.38)	(0.42)	(0.44)	(0.43)
DEC	(0.47)	(0.46)	(0.47)	(0.48)	(0.49)	(0.47)	(0.48)	(0.46)	(0.43)	(0.42)	(0.41)	(0.43)	(0.45)	(0.43)	(0.45)	(0.45)	(0.40)	(0.17)	(0.12)	(0.15)	(0.22)	(0.32)	(0.44)	(0.44)
Grand Total	**(0.40)**	**(0.41)**	**(0.43)**	**(0.44)**	**(0.42)**	**(0.37)**	**(0.26)**	**(0.15)**	**(0.05)**	**0.07**	**0.15**	**0.21**	**0.34**	**0.42**	**0.47**	**0.46**	**0.41**	**0.45**	**0.42**	**0.33**	**0.08**	**(0.19)**	**(0.33)**	**(0.38)**

Mini duck curve – distribution peaks later in the day

Color Scale

Highest Price

Lowest Price

In Closing

Findings and Conclusions

- Distribution is a key cost component in rate design and revenue allocation and by extension should be used to inform TOU periods
- Time dependence of distribution circuit peak loads is largely consistent with SCE's overall system peaks
- Similar to generation, distribution circuits can be functionalized into capacity (peak) and throughput (grid or non-peak) marginal cost components
- Distribution TOU analysis needs to be sufficiently forward-looking and inclusive of the load diversity across circuits
- The PLRF method can be used as an effective means of allocating time variant peak costs and is consistent with SCE's planning criteria and guidelines

Appendix

Forward-looking load studies by circuit for 2014 and 2024

2014 Recorded Load Standardized Variable Heat Map

Average of SV / Row Labels	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
WEEKDAYS	**(0.86)**	**(1.03)**	**(1.11)**	**(1.06)**	**(0.84)**	**(0.52)**	**(0.23)**	**(0.02)**	**0.17**	**0.34**	**0.48**	**0.60**	**0.74**	**0.86**	**0.93**	**0.95**	**0.96**	**1.00**	**0.95**	**0.87**	**0.67**	**0.33**	**(0.13)**	**(0.53)**
JAN	(1.02)	(1.19)	(1.28)	(1.28)	(1.14)	(0.80)	(0.39)	(0.25)	(0.15)	(0.09)	(0.06)	(0.05)	(0.05)	(0.03)	(0.04)	(0.05)	0.08	0.47	0.47	0.36	0.23	0.03	(0.31)	(0.68)
FEB	(1.04)	(1.20)	(1.29)	(1.31)	(1.16)	(0.80)	(0.41)	(0.25)	(0.18)	(0.12)	(0.09)	(0.08)	(0.07)	(0.06)	(0.07)	(0.08)	(0.04)	0.32	0.42	0.34	0.22	0.02	(0.32)	(0.70)
MAR	(1.18)	(1.30)	(1.35)	(1.27)	(1.01)	(0.59)	(0.39)	(0.28)	(0.20)	(0.13)	(0.10)	(0.08)	(0.05)	(0.05)	(0.06)	(0.08)	(0.10)	0.03	0.30	0.25	0.09	(0.19)	(0.58)	(0.92)
APR	(1.15)	(1.27)	(1.31)	(1.20)	(0.91)	(0.60)	(0.39)	(0.24)	(0.11)	(0.01)	0.07	0.13	0.21	0.26	0.30	0.30	0.26	0.23	0.44	0.44	0.26	(0.09)	(0.53)	(0.88)
MAY	(0.95)	(1.10)	(1.16)	(1.06)	(0.83)	(0.53)	(0.24)	(0.01)	0.21	0.40	0.56	0.69	0.85	0.98	1.08	1.10	1.04	0.92	0.87	0.90	0.70	0.30	(0.22)	(0.63)
JUN	(0.78)	(0.95)	(1.02)	(0.94)	(0.74)	(0.47)	(0.18)	0.08	0.31	0.52	0.70	0.87	1.08	1.26	1.40	1.45	1.39	1.25	1.03	1.02	0.88	0.49	(0.02)	(0.45)
JUL	(0.33)	(0.56)	(0.67)	(0.61)	(0.42)	(0.18)	0.16	0.50	0.83	1.17	1.47	1.76	2.06	2.31	2.48	2.55	2.48	2.29	1.97	1.82	1.62	1.16	0.58	0.06
AUG	(0.46)	(0.67)	(0.76)	(0.70)	(0.45)	(0.19)	0.10	0.41	0.72	1.04	1.35	1.65	1.96	2.20	2.38	2.42	2.32	2.10	1.82	1.73	1.44	0.95	0.37	(0.11)
SEP	(0.42)	(0.62)	(0.72)	(0.65)	(0.37)	(0.02)	0.23	0.54	0.85	1.17	1.48	1.79	2.11	[illegible]	2.53	2.55	2.41	2.18	2.07	1.92	1.55	1.01	0.39	(0.09)
OCT	(0.97)	(1.10)	(1.15)	(1.05)	(0.75)	(0.35)	(0.20)	(0.03)	0.15	0.33	0.47	0.63	0.83	0.98	1.08	1.07	0.98	1.03	0.98	0.80	0.53	0.12	(0.35)	(0.71)
NOV	(1.11)	(1.26)	(1.35)	(1.36)	(1.23)	(0.90)	(0.60)	(0.43)	(0.31)	(0.21)	(0.13)	(0.07)	(0.03)	0.02	0.04	0.05	0.23	0.47	0.41	0.27	0.13	(0.07)	(0.42)	(0.77)
DEC	(0.97)	(1.17)	(1.27)	(1.29)	(1.17)	(0.85)	(0.48)	(0.32)	(0.21)	(0.15)	(0.12)	(0.11)	(0.14)	(0.13)	(0.14)	(0.11)	0.26	0.57	0.55	0.46	0.35	0.17	(0.18)	(0.57)
WEEKENDS	**(0.88)**	**(1.07)**	**(1.19)**	**(1.22)**	**(1.18)**	**(1.09)**	**(0.96)**	**(0.76)**	**(0.55)**	**(0.36)**	**(0.20)**	**(0.07)**	**0.04**	**0.15**	**0.23**	**0.28**	**0.36**	**0.47**	**0.47**	**0.42**	**0.27**	**0.00**	**(0.37)**	**(0.71)**
JAN	(1.01)	(1.19)	(1.30)	(1.36)	(1.33)	(1.20)	(1.06)	(1.00)	(0.86)	(0.77)	(0.73)	(0.71)	(0.79)	(0.80)	(0.80)	(0.78)	(0.57)	(0.13)	(0.09)	(0.15)	(0.25)	(0.40)	(0.65)	(0.95)
FEB	(1.07)	(1.25)	(1.35)	(1.40)	(1.36)	(1.22)	(1.08)	(0.99)	(0.84)	(0.74)	(0.69)	(0.68)	(0.68)	(0.70)	(0.71)	(0.69)	(0.60)	(0.16)	(0.04)	(0.08)	(0.17)	(0.32)	(0.59)	(0.89)
MAR	(1.18)	(1.33)	(1.41)	(1.43)	(1.36)	(1.23)	(1.16)	(1.01)	(0.86)	(0.76)	(0.71)	(0.68)	(0.67)	(0.65)	(0.63)	(0.59)	(0.54)	(0.36)	(0.08)	(0.10)	(0.24)	(0.45)	(0.77)	(1.06)
APR	(1.22)	(1.35)	(1.42)	(1.41)	(1.32)	(1.24)	(1.14)	(0.98)	(0.85)	(0.77)	(0.74)	(0.73)	(0.72)	(0.71)	(0.69)	(0.65)	(0.60)	(0.53)	(0.19)	(0.15)	(0.27)	(0.51)	(0.84)	(1.13)
MAY	(0.94)	(1.12)	(1.22)	(1.24)	(1.19)	(1.17)	(0.99)	(0.75)	(0.54)	(0.35)	(0.21)	(0.07)	0.06	0.20	0.31	0.38	0.39	0.34	0.31	0.37	0.22	(0.08)	(0.48)	(0.83)
JUN	(0.79)	(0.98)	(1.10)	(1.13)	(1.09)	(1.08)	(0.89)	(0.64)	(0.39)	(0.17)	0.04	0.25	0.46	0.67	0.84	0.93	0.94	0.87	0.71	0.70	0.58	[illegible]	(0.19)	(0.58)
JUL	(0.39)	(0.64)	(0.79)	(0.85)	(0.83)	(0.83)	(0.60)	(0.26)	0.11	0.48	0.82	1.12	1.39	1.60	1.75	1.82	1.81	1.69	1.45	1.33	1.17	0.82	0.35	(0.09)
AUG	(0.40)	(0.64)	(0.79)	(0.85)	(0.82)	(0.79)	(0.63)	(0.32)	0.00	0.35	0.70	1.04	1.35	1.60	1.76	1.82	1.75	1.59	1.41	1.35	1.12	0.73	0.25	(0.19)
SEP	(0.54)	(0.76)	(0.90)	(0.95)	(0.89)	(0.80)	(0.68)	(0.35)	0.00	0.37	0.72	1.05	1.34	1.57	1.73	1.78	1.72	1.59	1.52	1.38	1.09	0.65	0.14	(0.29)
OCT	(0.96)	(1.13)	(1.23)	(1.24)	(1.17)	(1.03)	(0.97)	(0.75)	(0.54)	(0.34)	(0.16)	0.04	0.25	0.44	0.59	0.65	0.62	0.72	0.69	0.50	0.26	(0.08)	(0.49)	(0.82)
NOV	(1.13)	(1.30)	(1.41)	(1.45)	(1.42)	(1.29)	(1.18)	(1.07)	(0.90)	(0.77)	(0.68)	(0.63)	(0.60)	(0.58)	(0.55)	(0.52)	(0.28)	(0.02)	(0.04)	(0.13)	(0.25)	(0.42)	(0.70)	(1.00)
DEC	(0.94)	(1.15)	(1.28)	(1.34)	(1.32)	(1.20)	(1.05)	(0.97)	(0.83)	(0.76)	(0.73)	(0.75)	(0.77)	(0.78)	(0.78)	(0.72)	(0.27)	0.09	0.12	0.08	0.02	(0.12)	(0.39)	(0.72)
Grand Total	**(0.87)**	**(1.04)**	**(1.13)**	**(1.11)**	**(0.94)**	**(0.69)**	**(0.45)**	**(0.25)**	**(0.05)**	**0.12**	**0.27**	**0.40**	**0.53**	**0.64**	**0.71**	**0.74**	**0.77**	**0.83**	**0.80**	**0.73**	**0.55**	**0.23**	**(0.20)**	**(0.59)**

2024 Projected Load Standardized Variable Heat Map

Average of SV / Row Labels	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
WEEKDAYS	**(0.67)**	**(0.85)**	**(0.94)**	**(0.88)**	**(0.63)**	**(0.28)**	**(0.02)**	**0.03**	**(0.00)**	**(0.02)**	**(0.02)**	**0.03**	**0.16**	**0.34**	**0.56**	**0.77**	**1.02**	**1.27**	**1.31**	**1.24**	**1.03**	**0.65**	**0.14**	**(0.30)**
JAN	(0.85)	(1.03)	(1.13)	(1.14)	(0.98)	(0.59)	(0.15)	(0.03)	(0.17)	(0.32)	(0.43)	(0.50)	(0.51)	(0.42)	(0.30)	(0.13)	0.21	0.80	0.80	0.68	0.54	0.31	(0.06)	(0.47)
FEB	(0.87)	(1.05)	(1.16)	(1.17)	(1.00)	(0.61)	(0.17)	(0.09)	(0.22)	(0.34)	(0.41)	(0.46)	(0.46)	(0.36)	(0.28)	(0.17)	0.03	0.60	0.75	0.66	0.52	0.30	(0.08)	(0.50)
MAR	(1.02)	(1.15)	(1.20)	(1.11)	(0.82)	(0.35)	(0.17)	(0.27)	(0.43)	(0.56)	(0.66)	(0.73)	(0.74)	(0.69)	(0.57)	(0.38)	(0.16)	0.22	0.62	0.58	0.40	0.08	(0.35)	(0.72)
APR	(0.98)	(1.11)	(1.16)	(1.03)	(0.71)	(0.37)	(0.25)	(0.33)	(0.43)	(0.53)	(0.60)	(0.62)	(0.55)	(0.43)	(0.23)	(0.03)	0.17	0.39	0.77	0.78	0.58	0.19	(0.30)	(0.68)
MAY	(0.74)	(0.91)	(0.97)	(0.86)	(0.60)	(0.28)	(0.10)	(0.06)	(0.04)	(0.04)	(0.05)	0.00	0.14	0.32	0.57	0.81	1.00	1.13	1.23	[illegible]	1.09	0.65	0.08	(0.38)
JUN	(0.58)	(0.76)	(0.84)	(0.74)	(0.52)	(0.23)	(0.04)	0.02	0.05	0.07	0.09	0.16	0.34	0.57	0.85	1.10	1.28	1.38	1.32	[illegible]	1.24	0.81	0.25	(0.21)
JUL	(0.11)	(0.35)	(0.48)	(0.40)	(0.18)	0.08	0.32	0.45	0.57	0.71	0.85	1.06	1.37	1.69	2.02	2.29	2.45	2.51	2.34	2.23	2.02	1.52	0.88	0.32
AUG	(0.23)	(0.46)	(0.56)	(0.48)	(0.20)	0.09	0.32	0.42	0.52	0.64	0.79	1.01	1.32	1.63	1.97	[illegible]	2.35	2.39	2.24	2.16	1.86	1.32	0.69	0.16
SEP	(0.16)	(0.39)	(0.49)	(0.41)	(0.09)	0.30	0.52	0.62	0.72	0.86	1.01	1.23	1.57	1.92	2.25	[illegible]	2.61	2.61	2.56	2.39	2.00	1.41	0.74	0.20
OCT	(0.76)	(0.92)	(0.97)	(0.86)	(0.52)	(0.06)	0.09	0.05	0.00	(0.01)	0.00	0.09	0.31	0.56	0.81	1.03	1.20	1.44	1.38	1.18	0.89	0.44	(0.08)	(0.48)
NOV	(0.93)	(1.11)	(1.20)	(1.21)	(1.06)	(0.70)	(0.37)	(0.31)	(0.43)	(0.50)	(0.53)	(0.55)	(0.52)	(0.38)	(0.21)	0.02	0.48	0.81	0.74	0.60	0.44	0.21	(0.17)	(0.56)
DEC	(0.80)	(1.02)	(1.13)	(1.16)	(1.01)	(0.66)	(0.25)	(0.12)	(0.22)	(0.34)	(0.43)	(0.49)	(0.52)	(0.46)	(0.36)	(0.15)	0.48	0.89	0.87	0.76	0.64	0.44	0.07	(0.36)
WEEKENDS	**(0.69)**	**(0.90)**	**(1.03)**	**(1.07)**	**(1.02)**	**(0.93)**	**(0.84)**	**(0.80)**	**(0.80)**	**(0.79)**	**(0.78)**	**(0.72)**	**(0.62)**	**(0.45)**	**(0.23)**	**0.02**	**0.35**	**0.68**	**0.77**	**0.73**	**0.57**	**0.28**	**(0.13)**	**(0.51)**
JAN	(0.85)	(1.04)	(1.17)	(1.23)	(1.20)	(1.06)	(0.90)	(0.88)	(0.98)	(1.10)	(1.19)	(1.25)	(1.33)	(1.29)	(1.18)	(0.98)	(0.51)	0.14	0.18	0.11	0.01	(0.16)	(0.44)	(0.76)
FEB	(0.92)	(1.11)	(1.23)	(1.28)	(1.24)	(1.08)	(0.93)	(0.90)	(0.90)	(0.92)	(0.97)	(1.00)	(1.03)	(1.01)	(0.98)	(0.86)	(0.59)	0.05	0.22	0.18	0.08	(0.09)	(0.38)	(0.71)
MAR	(1.02)	(1.18)	(1.28)	(1.30)	(1.23)	(1.07)	(1.02)	(1.08)	(1.16)	(1.27)	(1.38)	(1.47)	(1.50)	(1.44)	(1.26)	(1.00)	(0.68)	(0.22)	0.20	0.17	0.02	(0.22)	(0.57)	(0.89)
APR	(1.06)	(1.21)	(1.28)	(1.27)	(1.18)	(1.09)	(1.10)	(1.16)	(1.23)	(1.34)	(1.46)	(1.53)	(1.57)	(1.52)	(1.36)	(1.10)	(0.81)	(0.46)	0.07	0.12	(0.01)	(0.27)	(0.65)	(0.96)
MAY	(0.74)	(0.93)	(1.05)	(1.07)	(1.01)	(1.01)	(0.94)	(0.88)	(0.85)	(0.86)	(0.86)	(0.79)	(0.66)	(0.49)	(0.23)	0.03	0.26	0.46	0.59	0.70	0.54	0.20	(0.24)	(0.62)
JUN	(0.59)	(0.80)	(0.93)	(0.95)	(0.92)	(0.93)	(0.87)	(0.81)	(0.78)	(0.77)	(0.76)	(0.64)	(0.45)	(0.18)	0.16	0.47	0.74	0.94	0.95	1.02	0.90	0.54	0.05	(0.37)
JUL	(0.18)	(0.44)	(0.62)	(0.68)	(0.65)	(0.66)	(0.53)	(0.40)	(0.25)	(0.08)	0.10	0.33	0.60	0.89	1.20	1.48	1.70	1.84	1.76	1.69	1.52	1.14	0.63	0.15
AUG	(0.16)	(0.43)	(0.60)	(0.66)	(0.62)	(0.59)	(0.52)	(0.41)	(0.28)	(0.10)	0.11	0.38	0.68	1.00	1.30	1.57	1.74	1.83	1.79	1.75	1.50	1.08	0.55	0.07
SEP	(0.30)	(0.54)	(0.70)	(0.75)	(0.69)	(0.59)	(0.51)	(0.41)	(0.28)	(0.12)	0.08	0.33	0.64	0.97	1.29	1.61	1.83	1.95	1.95	1.81	1.49	1.01	0.45	(0.02)
OCT	(0.76)	(0.94)	(1.06)	(1.07)	(0.99)	(0.83)	(0.79)	(0.78)	(0.76)	(0.68)	(0.57)	(0.44)	(0.22)	0.08	0.37	0.62	0.82	1.08	1.05	0.85	0.58	0.21	(0.23)	(0.61)
NOV	(0.96)	(1.14)	(1.26)	(1.31)	(1.27)	(1.13)	(1.01)	(1.04)	(1.13)	(1.21)	(1.27)	(1.30)	(1.25)	(1.11)	(0.92)	(0.64)	(0.10)	0.27	0.24	0.14	0.01	(0.18)	(0.49)	(0.81)
DEC	(0.78)	(1.00)	(1.14)	(1.21)	(1.19)	(1.05)	(0.89)	(0.85)	(0.92)	(1.01)	(1.11)	(1.18)	(1.22)	(1.18)	(1.08)	(0.83)	(0.11)	0.35	0.38	0.34	0.26	0.12	(0.18)	(0.55)
Grand Total	**(0.68)**	**(0.87)**	**(0.96)**	**(0.93)**	**(0.75)**	**(0.48)**	**(0.27)**	**(0.22)**	**(0.25)**	**(0.26)**	**(0.26)**	**(0.20)**	**(0.08)**	**0.10**	**0.32**	**0.54**	**0.82**	**1.09**	**1.15**	**1.08**	**0.89**	**0.53**	**0.06**	**(0.37)**

Mini duck curve – distribution peaks later in the day

Color Scale
Highest Price
Lowest Price

Attachment C

Time Differentiated Distribution Costs & TOU Period Determination (White Paper)

TIME DIFFERENTIATED DISTRIBUTION COSTS & TOU PERIOD DETERMINATION

Monterey Conference – June 2016

AUTHORED BY:

REUBEN BEHLIHOMJI
MANAGER, MARGINAL COST
SOUTHERN CALIFORNIA EDISON

TABLE OF CONTENTS

TABLE OF FIGURES

Introduction

Southern California Edison's (SCE) Time of Use (TOU) periods were established and have not changed in over three decades. SCE's TOU periods were established in an environment of vertically integrated utilities where fossil fuel-fired generation costs and the avoidance of marginal spending for fossil fuel generation capital and Operations & Maintenance (O&M) were the primary considerations of the utilities' and regulatory bodies. Therefore, TOU pricing structures were designed to manage demand focused primarily on the generation component of electricity rates. Today, we face a deregulated industry where utility owned generation comprises a small fraction of the generation portfolio. Marginal utility capital spending is largely found in the distribution function. SCE's base distribution costs comprise approximately 35 percent of the utility's total revenue requirement, while base generation comprises about 15 percent. From an investment standpoint, distribution capital expenditures account for nearly 60 percent of SCE's total capital expenditure as a company. These statistics emphasize the importance of the role that the distribution system plays in pricing, investment planning, and operational dimensions of SCE as a company, and raise two key considerations that previously did not play a role in TOU period determination. These considerations are:

- Should distribution costs be a determinant in developing TOU periods for electricity pricing?
- What portion of distribution costs are deemed as time variant and driven by peak load needs?

As SCE's distribution system continues to evolve with advances in innovation and technology (e.g., advanced metering or Distributed Energy Resources (DER) as alternatives to capacity expansion), smart rate design should evolve for a more collaborative interface with our customers. Advanced metering has contributed to a renaissance in conceptualizing how time differentiated pricing can increase the sensitivity of individual customers to make choices on how and when they use energy. DERs, in concert, will contribute to the increased likelihood that the distribution system will incrementally serve two primary functions: (1) peak capacity needs based on the hours when distribution infrastructure will experience peak load to and from customers, and (2) a "throughput" or energy based function to allow for a base amount of electricity flow to and from customers. California's policy objective of decarbonizing the grid continues to play an important role in establishing the guiding principles in which the Commission must act when promoting relevant directives in support of its own policies. While the Commission has a broad array of options on hand, time of use (TOU) periods are a powerful tool that maintains the efficacy of electricity pricing, by having a profound impact on customer choice and how their load behavior affects the economic costs borne by them and the utility. There exists a long standing precedence at the Commission that costs are a key element that inform decisions on revenue allocation and rate design; the final goal being that of minimizing overall costs borne by the customer. Therefore, costs and all of the key drivers, should continue to play an equally important role in the determination of TOU periods.

The evolving role of the distribution system with respect to bidirectional time variant delivery of power, means distribution system marginal costs should play a greater role when defining time of use periods. The utility has an obligation of service and commits long term investment planning for both the generation/procurement of power and the delivery of power to its customers. Principles that have long set the precedent behind using the generation function as the key determinant of time variant cost drivers, and therefore TOU periods, can also effectively translate to distribution system costs. The timing of innovations and the increased propensity for consumer choice, are helping shape the landscape of how the distribution system will eventually evolve in the future. Traditionally, the primary options available to utilities when distribution capacity constraints were reached included either load transfers between circuits in the short term, or the buildout of new line and system capacity for the long term. As limitations of load transfer between circuits are reached, the need for new capacity is typically triggered by the peak load point experienced on a distribution circuit, regardless of whether the peak was sustained or concentrated in a relatively small period. Traditionally this situation would lead to incremental capital spending on distribution infrastructure, and the pattern would repeat itself as load grew. With DERs becoming more prevalent across the distribution landscape, the availability of such options is presenting a situation where the distribution system peak is migrating to later in the day, in effect creating a distribution system "duck curve". The presence of such a patter lends credence to the use of time dependent distribution marginal costs in setting TOU periods.

Current Generation Centric Practice of Determining TOU Periods

The precedence in defining TOU periods, as established by the Commission, has typically been based on system level generation costs. TOU periods are a means to an end, in that they inform the pricing structure required to help consumers distinguish between periods of high and low marginal costs. The *system*, when defining such periods in the past, has typically been the bulk power system (i.e., avoided generation energy and capacity). As the current bulk power system is controlled by the California Independent System Operator (CAISO), the operating constraints of the CAISO when managing the supply and demand for energy and capacity at the generation level would be the primary determinants if TOU periods were determined today with no change in the current practice. However, the *delivery* of energy has, and will continue to be an important cost driver for utilities. As the grid becomes smarter, coupled with an increased proliferation of DERs, the operating constraints around the delivery of power to and from a utility's customer is also becoming increasingly relevant. While distribution costs have always been used as one of the primary cost drivers in the allocation of revenue requirement to rate groups, they have traditionally not been used in the determination of time of use periods. It is noteworthy to mention however, that until around ten years ago, SCE did have time differentiated distribution demand charges for C&I customers. Including distribution costs when defining time of use periods is important due to the following reasons:

1. Utilities have deployed advanced metering technology that enables customers to adapt to more dynamic and refined price signals in order to better manage and inform their load behavior.
2. As the grid evolves, smart rate design and time sensitive price signals embedded in rates will be needed to help utilities manage the time sensitive nature of bidirectional power flow to and from customers on the distribution grid.
3. Innovation and the rapid deployment of DERs on the distribution grid is a benefit to functionalizing distribution grid costs as energy and capacity, similar to that done for generation. Such functionalization of costs helps promote efficient pricing thereby minimizing costs for consumers as a whole.
4. Distribution will continue to be a key driver of marginal costs experienced by the Investor Owned Utilities (IOUs) in the delivery of power to customers. Time sensitive peak load on the distribution system trigger variable distribution marginal costs.

Some of the criticism against the use of distribution marginal cost for TOU period definition is centered on the premise that there exists an expansive diversity in distribution system peaks which acts as a deterrent when analyzing the effect of such diversity across the distribution regions and the system as a whole. For example, different parts of the system with a predominantly different composition of customers, will have different load shapes and different coincidence factors. Principles of cost causation should dictate that customers receive price signals and therefore pay for costs they incur on the system. Pricing structures that promote locational incentives are a possible means of addressing such concerns. However, appropriately defined marginal cost that effectively capture distribution system load diversity can play an important role when informing TOU periods. This paper describes a means of capturing the diversity of peak load risk across circuits and/or substations. In the following sections, we discuss (1) methods that apportion the “value” of distribution marginal costs between peak load (variable) and non-peak load (grid) dependent parameters, and (2) the methodology and rationale behind the Peak Load Risk Factor (PLRF) as a tool that helps allocate peak load variable marginal costs to time of use periods. Pacific Gas & Electric (PG&E) uses a similar approach (Peak Cost Allocation Factor - PCAF) but disaggregates the data by Distribution Planning areas and analyzes the timing and magnitude of the peak load experienced by the distribution system for these areas. PG&E’s PCAF methodology examines distribution load within each region.[1]

Discussion

The topology of SCE’s distribution system is comprised of a network of substations (B Banks) that convert sub-transmission voltages (66 kV and 115 kV) to distribution voltages (33 kV and below), and includes distribution circuits used for the delivery of power from B Banks to specific customer load points. SCE’s distribution system is primarily an overhead (OH) system with a sizable portion of the system being underground (UG). The OH system comprises of poles, conductor (wire) and associated equipment. The UG system comprises of structures, cable and associated underground equipment. Line transformers and service cables comprise the segments of the system that typically allow for the “connection” of customers to SCE’s distribution system. When we discuss distribution capacity in this paper, we are primarily focused on distribution mainline feeders or circuits and B bank transformers (“B banks”).

Functional utilization of the distribution system should inform and guide investment planning for distribution system capacity. In this paper we discuss some of the rationale that supports a shift in the methods of determining TOU periods to account for time and non-time variant distribution functional utilization. As distribution system infrastructure supports both the flow of energy (or throughput), as well as peak capacity needs, understanding system utilization as expressed by load factor across different circuits is essential. To illustrate utilization, SCE has calculated annual load factors (defined as the annual average demand divided by the annual peak demand) for each circuit and B Bank. The frequency histograms illustrate the percentage of circuits or B Banks and their associated annual load factors. The graphs help understand load factor as a proxy of utilization for each circuit or B Bank on the distribution system. Ninety-nine percent of circuits and about ninety-eight percent of B Banks have load factors of 65 percent and below. As depicted in the following graphs, annual circuit load factors typically range around 25 to 35 percent on average for circuits (Figure 1), and around 35 to 45 percent on average for B banks (Figure 2) on SCE’s system. Low load factors indicate that peak loads are experienced on circuits or B banks for a relatively short duration of time in the year, typically driven by high air-conditioning loads during heat waves. For additional reference, SCE has also included regional load factor graphs in Appendix A, Figure 11 through Figure 14.

FIGURE 1: DISTRIBUTION OF CIRCUIT LOAD FACTORS (YEAR 2014)

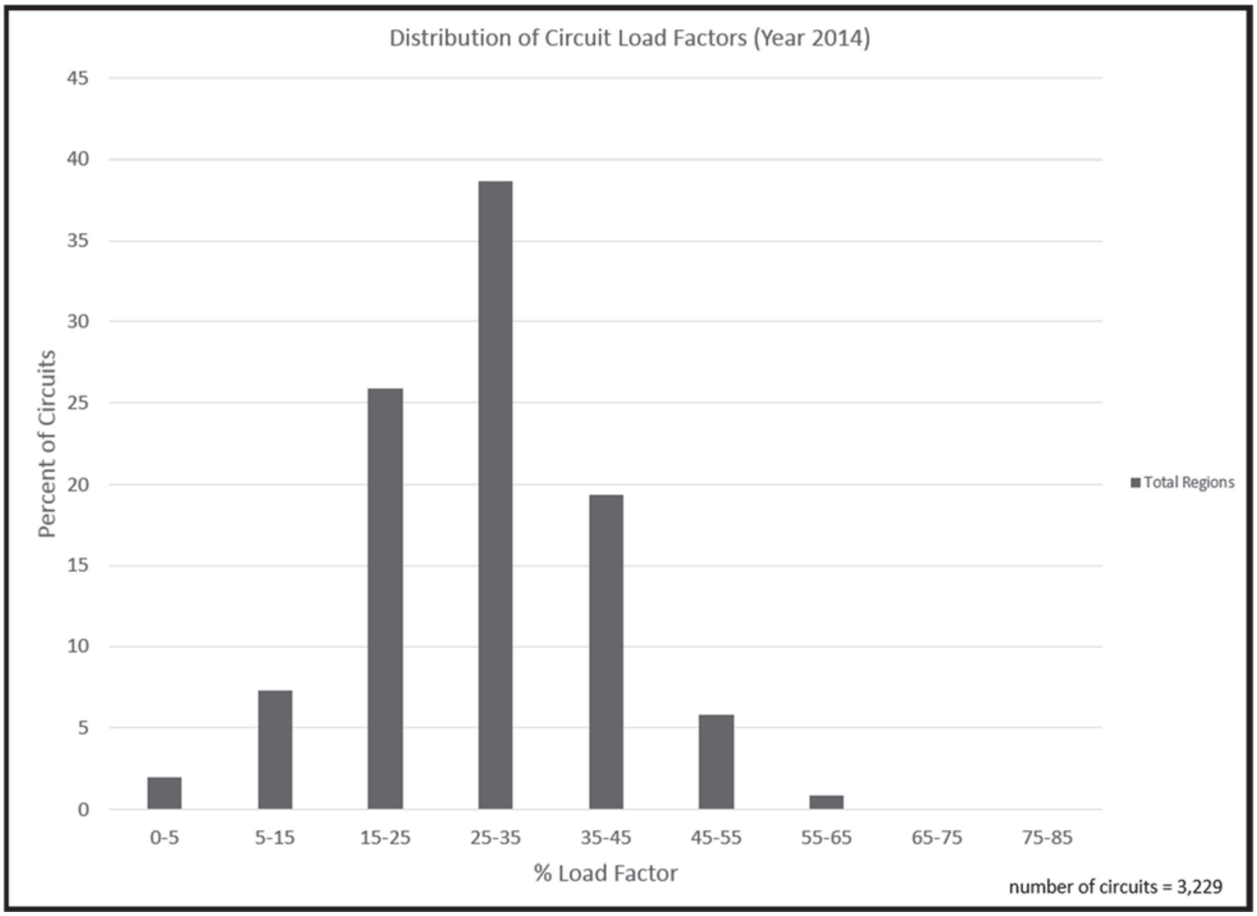
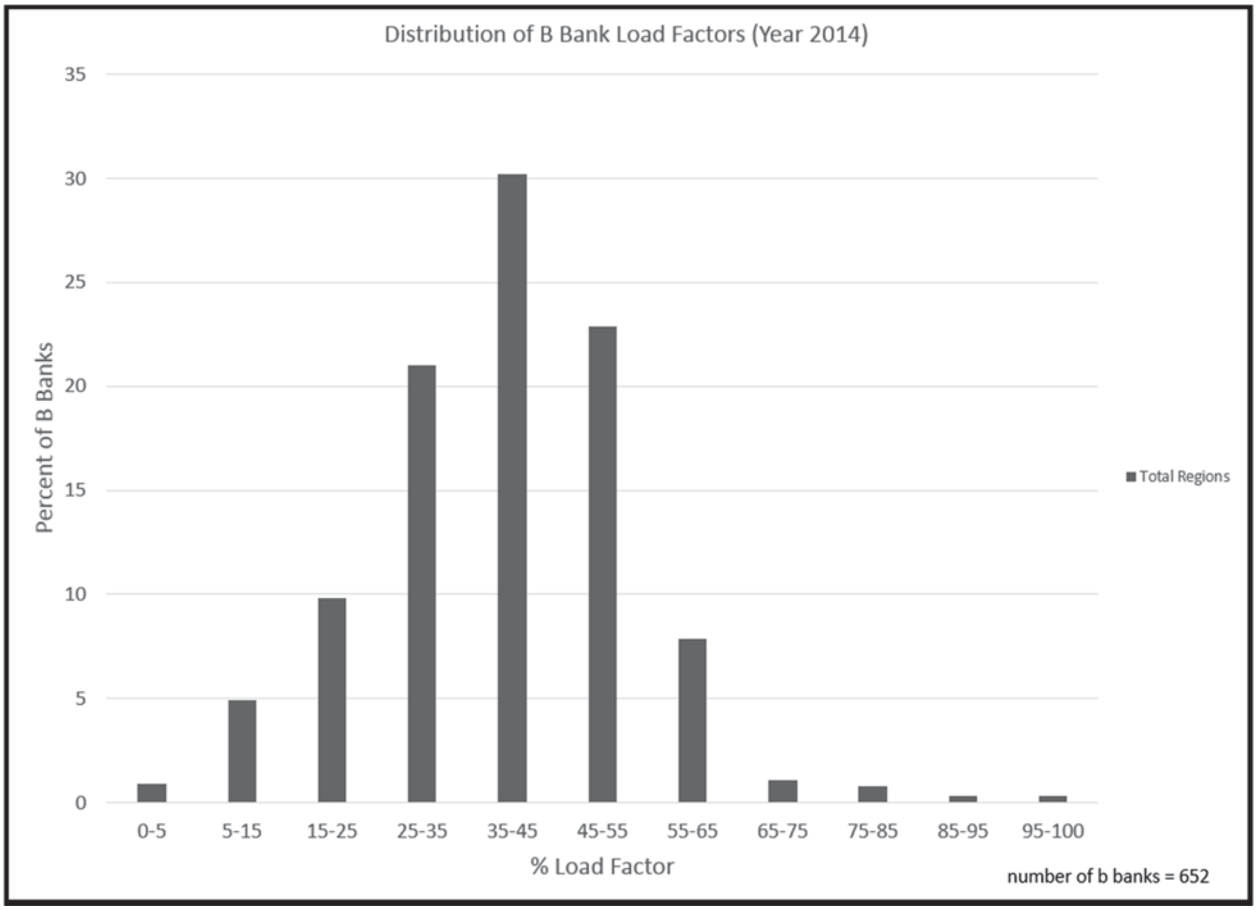


FIGURE 2: DISTRIBUTION OF B-BANK LOAD FACTORS (YEAR 2014)



The current practice of viewing marginal distribution infrastructure cost solely as a source of distribution capacity, driven by a single peak load point, works well in a world where load drivers and capacity constraints are resolved with a singular capacity planning option, namely load transfers or adding circuit capacity. Such a method minimizes the importance of the "throughput" (flow of energy), and essential function of distribution circuits. In order to better optimize capacity utilization, and therefore cost assignment, there appears to be a need for a dual focus of apportioning distribution system marginal costs based on the drivers of both absolute peak and grid throughput. The allocation of peak load costs would typically follow the timing and frequency with which such peak loads are experienced on the distribution system. The allocation of Non-peak load costs (or grid costs) on the other hand, would follow the cost drivers that represent the functionality of the grid as a medium used for the delivery of energy to and from customers (average circuit level demand could be one such driver). In this paper we describe the PLRF as a means of allocating the peak load variable component of marginal distribution capacity costs across the hours when such peak load is experienced. In a world where technology has vastly improved the economics of a diverse suite of capacity planning options, a focus on peak and frequency of such peaks, should more appropriately promote the efficient deployment of capital investment. In the sections below, we have enumerated current practice and possible options on determining absolute peak and grid throughput distribution cost components.

Existing Principles for Allocating Distribution Marginal Costs and Rate Design– Design Demand

Planning for Distribution Capacity

Current process dictates that investment planning for the distribution system is done over a 10 year planning horizon to accommodate a one in ten planning event (i.e., 1 in 10 year heat storm). Planning over a 10 year horizon allows sufficient time for deploying distribution infrastructure to meet projected load needs. This helps ensure that capacity planning is done with sufficient reserve and contingency, when providing safe and reliable power to our customers. Specific criteria help distribution system planners identify the need and magnitude of capacity on the distribution system, a key determinant of the marginal distribution costs used for revenue allocation and rate design. These criteria are outlined in Appendix B.

SCE's Current Revenue Allocation Principles

SCE estimates distribution design demand marginal cost using a modified NERA regression method[2]. The regression method uses ten years of historical data and five years of forecast data for both capital investment (y-axis) and designed or planned capacity (x-axis). The slope of this regression plot defines the marginal cost of distribution design demand for the system as a whole.

When allocating marginal distribution capacity costs to rate groups, SCE determines the marginal contribution of a rate group's demand at the time of a "typical" circuit peak. This is done by running a stochastic model simulating the impact of a sample group of customers to the typical circuit peak. The simulation results are averaged across a large sample group of customers which then defines the rate group's Effective Demand Factor (EDF).

- A "typical" circuit is modeled to have a representative mix of customers of all rate groups. For the typical circuit specific to a rate group, each circuit is weighted by the quantity of customers of that rate group on each circuit.
- Rate group EDFs are defined as the ratios of the circuit peak coincident demands (kilowatt – kW) to the annual non-coincident peaks of the customers in each rate group.

The analysis is performed with respect to the single peak load point of the typical circuit and is intended to capture the effects of customer diversity within a rate group and among different rate groups. In addition, the single peak load point of the typical circuit is the primary driver of planning for distribution capacity needs on the system. The diversity of customer demand within a rate group and among rate groups on distribution circuits implies that there exists a time dependency in the occurrence of peaks on the distribution circuits. Capturing the effect of such diversity is important when analyzing time periods during which the distribution system experiences peak load during the seasonal hours of the year. The use of Non-Coincident Peak (NCP) demand in determining overall distribution costs, underscores that connected load on the distribution circuits is a key driver to be considered when analyzing how such load affects circuit peaks and therefore contributes to marginal spend for distribution capacity. As such, distribution marginal cost revenue responsibility of a rate group is determined as product of the rate group EDF, the summed annual NCP's for that rate group, and the Distribution unit marginal costs.

SCE's Current Rate Design Practice

Today, distribution infrastructure costs based on the design demand component of distribution rates and recovered either through non time differentiated volumetric charges (for residential customers) or non-time differentiated demand charges (for non-residential customers). The method is premised on the rationale that connected load, as defined by a customer's NCP, is the definitive cost driver underlying distribution system marginal costs and revenue requirements. The use of NCP also presupposes that customers within a particular rate group share consistent load patterns resulting in similar contributions to typical circuit peaks. This has resulted in SCE designing rates for the recovery of distribution costs such that customers within a rate group pay the same distribution charge, regardless of the time when their peak demand occurs on the distribution circuit. In other words, a customer that imposes their peak demand of 5 kW at 3 a.m. on a winter weekend pays the same monthly charge for distribution as a customer imposing their 5 kW peak demand at 5 p.m. on the peak summer day.

While this section describes SCE's current methods of revenue allocation and rate design, the following sections describe a potential change to the current approach, where distribution marginal costs could be split into functional cost components of capacity and energy, namely peak load and non-peak load costs.

A Perspective on Cost "Valuation" for Design Demand: Drawing the Line - Fixed (Non-Peak) Versus Variable (Peak) Distribution Capacity

There exists a breadth of discussion on the precedence and analysis that supports the understanding of distribution system capacity costs. The context of splitting such costs between fixed (costs that do not change with the level of demand or usage) versus variable (costs that vary based on the level of demand and usage) are the cornerstone of discussions IOUs face with respect to appropriately setting the right price signal in rates. What all parties involved in such discussions should keep at the forefront of their analysis are the basic guiding principles Professor James Bonbright enumerated as part of his work.[3] Some examples of such guiding principles would include promoting efficiency in pricing, fairness in the allocation of costs among customers, and that pricing should reflect present and future costs in the provision of electricity. Cost of service studies used to inform opinions on the split between fixed and variable costs should take into consideration some of the historical precedence that has driven the practice and methods used by utilities when designing rates. Within the framework of California IOUs, the Commission has a long standing precedence of marginal cost pricing for the functionalized breakdown of costs between energy, demand and customer related cost supported by the ten guiding principles suggested by Professor James Bonbright. These same principles apply to the determination of TOU periods, which underlie the rate designs.

In this section of the paper, we describe a host of methods that can be used in splitting distribution cost recovery into two basic components: (1) the portion of distribution system capacity that is *peak load variant* and therefore will be allocated based on the PLRF method described below; and (2) the portion of distribution system capacity that is non-peak load variant and therefore would be allocated based on a measure of average demand on the distribution system. By splitting costs in such a manner, distribution system costs could be bifurcated similar to generation, as serving a dual purpose of energy (or throughput) and peak capacity needs. Many methods exist when defining this demarcation point for distribution assets between peak load variant and non-peak load variant. All of the methods for allocation distribution capacity costs between these two categories would have to be balanced with the needs for consumer adoption, fairness of cost responsibility impact, sufficiency and the prospect of rate stability.

Current Marginal Cost Approach

The current marginal cost approach of using the Real Economic Carrying Charge (RECC) method allocates revenues between functionalized cost drivers such as distribution and generation. Distribution costs are further broken down into design demand and customer charge components. The driver for design demand marginal cost is load growth and the driver for customer marginal cost is number of customers. Customer charges (dollar per customer per month) represent the portion of the utility's distribution costs that are not dependent on the level of demand or usage of the system, but on costs necessary to provide service to customers, and therefore fixed. Under this premise, "all" distribution capacity marginal costs for designed demand are deemed peak load driven. Design Demand costs are allocated to rate groups based on the EDF method discussed in the previous section of this paper. Such costs are recovered based on non-time differentiated, facilities demand (kW) charges or distribution energy (kWh) charges as applicable to specific rate groups. Based on the 2015 GRC SCE proposed distribution recovery based on a split of 68 percent from demand marginal costs (variable by demand) and 32 percent from customer marginal costs (fixed per customer). However, in summary for all rate groups, when finally reflected in rates, this split was around 88 percent design demand (variable by demand) and 12 percent customer (fixed per customer), driven primarily by precedential policy that limits fixed charges in residential rates.

NERA/FERC Method – Refining the Regression Model to an Accounting Perspective

The NERA/FERC method is based on the concepts put forth in the 2005 NERA paper called "Rethinking Rate Design for Electricity Distribution Service."[4] The FERC Form 1 captures capital expenditures for distribution FERC accounts which are categorized into accounts that tend to reflect investments made in non-peak load (or grid) and peak load (or variable) type assets. The benefits to this model is that it can be perceived as a standardized approach based on existing FERC accounting principles that outline exactly what capital expenditures should be recorded into their respective asset accounts.

FIGURE 3: DISTRIBUTION PLANT ACCOUNT FERC FORM 1 CLASSIFICATIONS

Distribution Plant				
Type	Group	Acct#	Description	
Fixed	Land	360	Land and land Rights	
Variable	Sub	361	Structures and Improvements	
Variable	Sub	362	Station Equipment	
Fixed	Lines	364	Poles, Towers, and Fixtures	
Fixed	Lines	365	Overhead Conductors and Devices	
Fixed	Lines	366	Underground Conduit	
Fixed	Lines	367	Underground Conductors and Devices	
	CMC	368	Line Transformers	Customer Marginal Costs accounts
	CMC	369	Services	
	CMC	370	Meters	

For distribution capital expenditures, FERC guidelines dictate that such expenditures be recorded to FERC accounts 360 through 369. This approach is complementary to our existing process of marginal cost valuation, wherein capacity spend related to load growth in these specific accounts are used and applied to SCE's Design Demand regression model.

The basic premise of such a FERC based bifurcation is as follows:

- Peak load variable components of distribution capacity are assets recorded in substation FERC accounts 361 (Substation Structures & Improvements), 362 (Substation Equipment) and 35X (Sub-transmission

FERC Accounts). Costs included in the sub-transmission FERC accounts are not uniquely recorded but such costs could be extracted from the studies currently in place where sub-transmission system (66kV and 115kV) investments are allocated between FERC-jurisdictional assets and CPUC-jurisdictional assets.

- Non-peak load variable assets recorded in distribution circuit class accounts would typically be investments made in circuits, recorded in accounts 364 through 367.
- Assets recorded in accounts 368 (Line Transformers) and 369 (Service Drops) are typically classified as customer related costs along with meters which is recorded in account 370.

If customer marginal cost recovery is held constant as implemented in rates at 12 percent (due to policy governed residential rate limitations), using such an approach results in a split of 72 percent non-peak load (fixed) and 18 percent peak load (variable) design demand marginal costs. While these percentages represent an order of magnitude estimate based on preliminary analysis, a more accurate estimate can be determined with a more exhaustive data set.

NERA/FERC Method – Adjusted for Circuit Line Miles

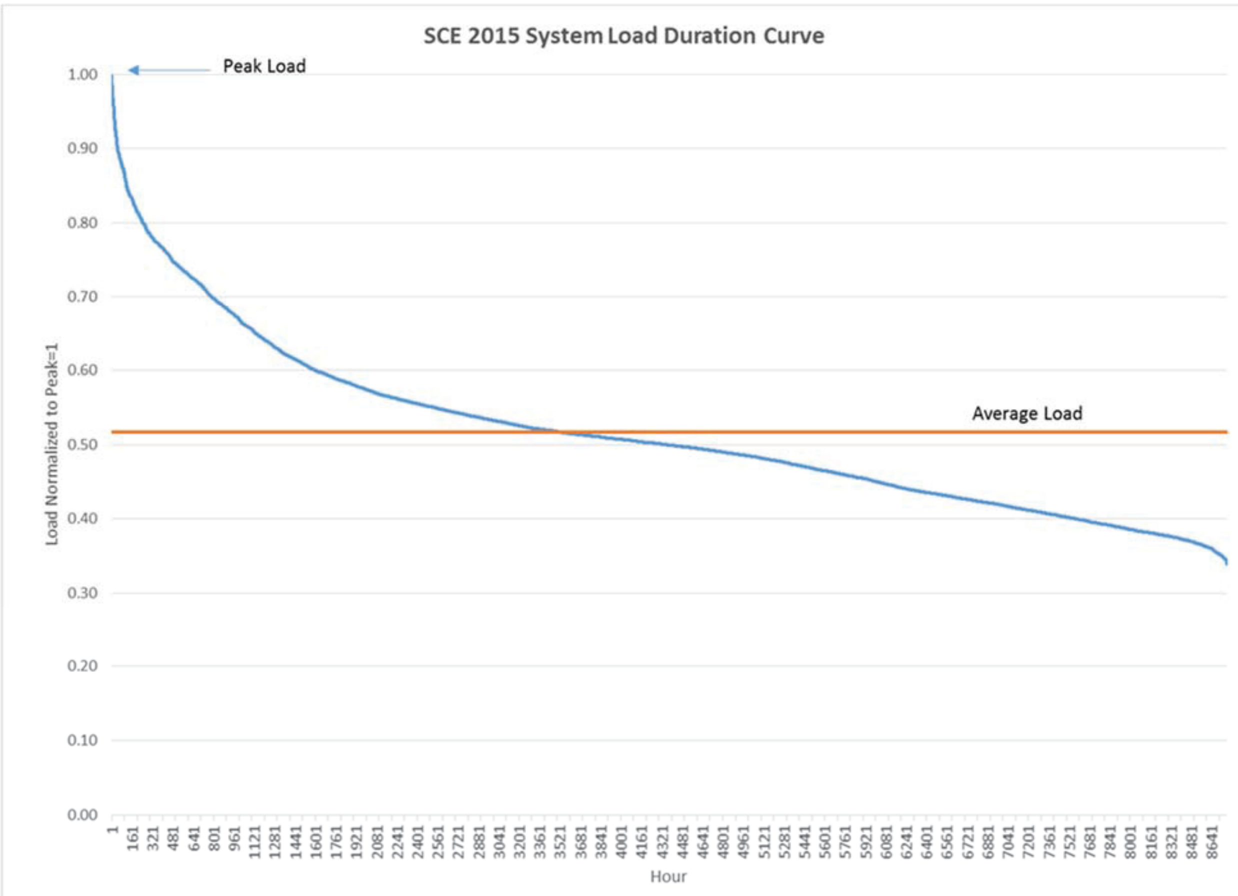
This is an adjustment to the basic NERA/FERC approach described above, and uses distribution circuit miles to further refine the allocation of the peak load and non-peak load variable allocation of costs. When reviewing FERC accounts for distribution circuit assets (360, 364 through 367), it is worth considering that some portion of distribution circuit lines are more prone to peak load capacity needs while others are not. Distribution circuit line miles can be analyzed and appropriately split between "main backbone" line miles versus what are typically considered "radial" extensions from these "main backbone" miles. While an estimate, the radial line miles would typically represent the portion of the system that could be considered non-peak load variant and the "main backbone" line miles would represent portions of the circuit that could be considered peak load variant. This method of using a split of line miles to allocate costs would be consistent with the FERC process of splitting costs and investment between FERC-jurisdictional and CPUC-jurisdictional assets when setting FERC rates.

An analysis of circuit miles resulted in a split of SCE's distribution system at around 27 percent comprised of main circuit miles and 63 percent comprised of radial circuit miles. If customer marginal cost recovery is held constant, as implemented in rates at 12 percent (due to policy governed residential rate limitations), using such a line split refinement to the FERC/NERA approach results in a split of 45 percent non-peak load (fixed) and 43 percent peak load (variable) design demand marginal costs. While these percentages represent an order of magnitude estimate based on preliminary analysis, a more accurate estimate can be determined with a more exhaustive data set.

Circuit Utilization – Installed Capacity Split between "Energy" and "Peak Capacity" Needs

As the utility's distribution system evolves into a system designed to accommodate the delivery of power to and from customers, two themes become relevant – throughput and peak capacity needs. A proxy of measuring throughput is the hourly load factor experienced on a circuit and a proxy of measuring peak capacity needs could be determined by analyzing the time dependent relationship of peak load, defined by a distribution asset's load duration curve. When viewing distribution infrastructure as serving these two purposes, the means in which infrastructure is utilized becomes a key determinant of such associated costs. This could be studied by analyzing asset utilization for both circuits and substations when meeting average demand and peak demand. When discussed in the limit, say for a single hypothetical circuit for a given year, the duration and extent to which that circuit provides capacity to meet average demand needs would represent the portion of circuit capacity that is most utilized. Therefore, if the intent is to optimize utilization of this hypothetical circuit, the ideal level of required capacity would be at some level where the circuit was operating at an electrically sufficient load factor to meet the average demand needs imposed on the circuit. This average demand portion of capacity would be served, in a relatively stable manner over the duration of the year and would change only with changes in the annual load factor experienced on that circuit. This portion of the circuit capacity would not be affected by the time and duration that the circuit experienced its peak load. Figure 4 below provides an illustrative load duration curve to capture the conceptual framework behind such an approach.

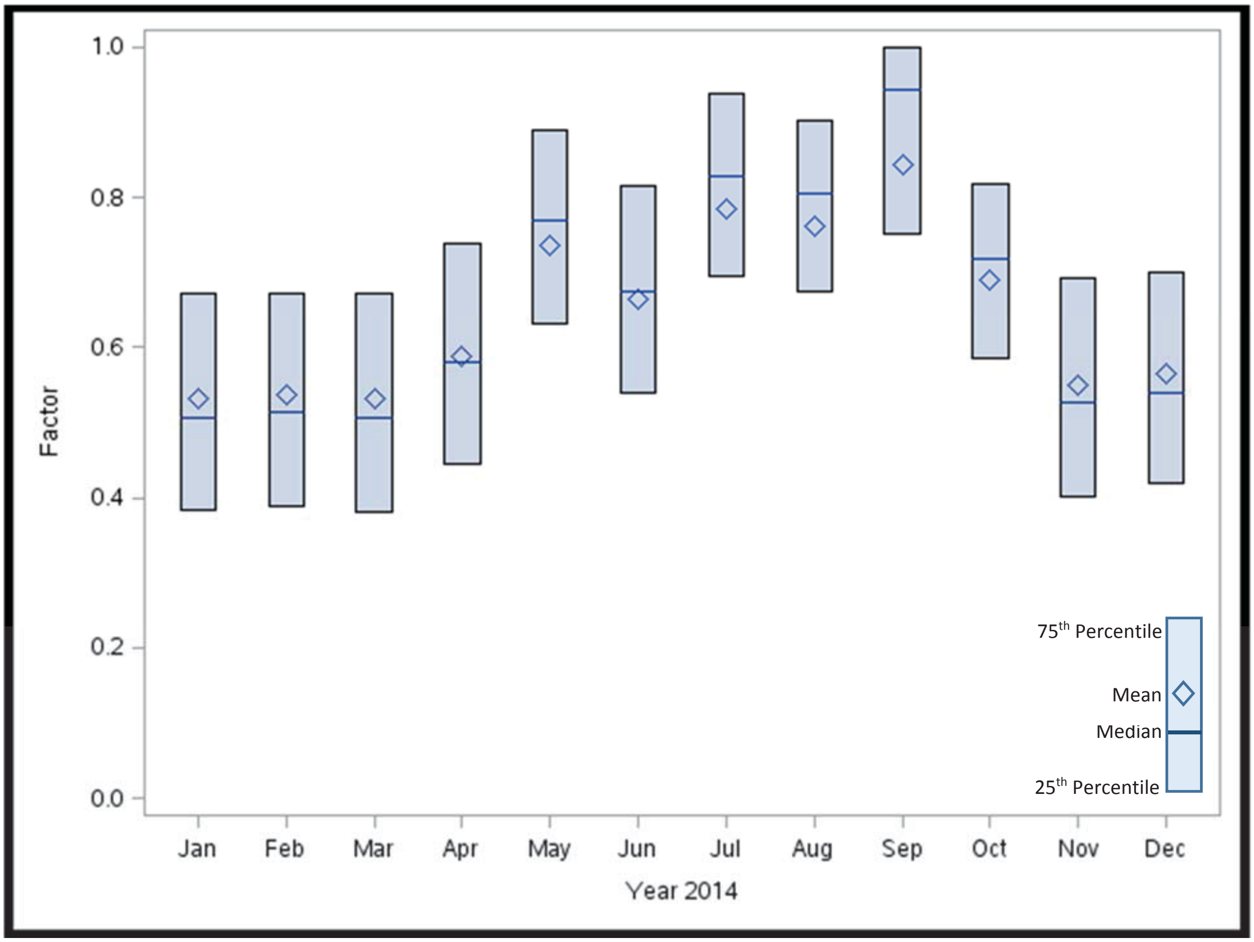
FIGURE 4: LOAD DURATION CURVE



Taking the analysis a step further, the peak demand needs of this hypothetical circuit, could be met by installing a sufficient level of excess capacity to meet peak demand needs. The issue here is that utilization of this excess level of capacity would be low and would vary significantly by the amplitude and duration for which peak demand was experienced on this circuit. The time and the duration when such peak demand was experienced would be the primary driver of capacity needs on the distribution system and would be a key determinant in the valuation and allocation of peak load (variable) marginal costs. This peak load analysis could then be extrapolated to all circuits on the system, and a load weighted average could be derived for the distribution system as a whole. The load weight used in such an analysis would be the maximum demand experienced on each circuit. This method would result in a utilization split of the distribution system between “peak” and “non-peak” load capacity which could then be used to further split distribution marginal costs between peak load variable and non-peak load variable marginal costs.

Figure 5 is a simple way to demonstrate how the distribution system was utilized for the year 2014. The values on the y-axis are calculated by dividing each circuit's monthly maximum demand to its annual maximum demand, whereas the x-axis is the month of the year. This box plot demonstrates a relative dispersion of how circuits are utilized over the span of the year.

FIGURE 5: DISTRIBUTION UTILIZATION BOX PLOT (YEAR 2014)



Minimum Cost Method (NARUC) – Embedded Cost Approach

This approach attempts to analyze the minimum distribution buildout needed to support a specific base amount of load required on the system. This approach has been further enumerated in NARUC's Electric Utility Cost Allocation Manual.[5] The process simply enumerates a perspective of costing out the build of a minimum level of distribution assets required to meet minimum customer needs. This minimum portion of system costs are considered non-load dependent with the remainder considered load dependent. Such a process is typically used in conjunction with an embedded cost approach when allocating distribution costs on the system. Analysis done in the past using such an approach was filed in SCE's Post-transition Ratemaking Proceeding (Application 99-01-034).

Results of Operations – General Rate Case (GRC) Phase 1 Approach

This approach attempts to look at the Capital and O&M spend being proposed in Phase 1 of the GRC as detailed in the Results of Operations (RO) model. Expenditures for Capital and O&M could be grouped into four discrete buckets: (1) short run fixed costs, (2) short run variable costs, (3) costs included in the RECC component (considered long run variable) when determining utility marginal costs; and (4) costs that are not included in the RECC component of utility marginal costs. The hurdles with such an approach lie in the basic differences in accounting valuation and economic valuation. The study, however, could be performed to inform the foundational context of using short versus long-run costs when analyzing distribution system marginal costs. When splitting marginal generation costs, energy costs are valued using a short run framework and peak capacity costs are valued using a long-run framework. While this study stimulates the discussion on valuation constructs between short- and long-run, the analysis should consider both perspectives in order to draw an appropriate and sufficient conclusion.

FIGURE 6: CAPITAL AND O&M EXPENDITURES

Short Run Considerations

Fixed	Variable
Depreciation	O&M
Depreciation of General Plant	Escalation
Taxes (property, payroll, and income)	OOR
Net Operating Revenue	

Long Run Considerations

Included in RECC	Not included in RECC
Depreciation	O&M – Included as an adder to marginal costs
Escalation	Depreciation of General Plant
Net Operating Revenue	Payroll taxes
Property & Income Taxes	

A Perspective on "Allocation" of Peak Capacity Costs

Distribution system costs are a key marginal cost driver experienced by the utility and should be equitably considered when defining time of use periods. Doing so, ensures that customers receive the appropriate price signal for costs that their load behavior imposes on the distribution system. Below, we have presented a simple method to analyze time period definitions based on planning guidelines used by Distribution Planning. Such a method allows for the allocation of variable or peak load dependent marginal costs to time periods, with an intent to more effectively inform revenue allocation and rate design for peak load marginal costs of the distribution system.

In the following section, we'll walk through a series of steps used when reviewing the load profile of the distribution system. As an illustration of the time variant nature of load dispersion on SCE's circuits, SCE has included a heat map plot[6] of a standardized variable of recorded load for the year 2014, by hour and month (Figure 7 – Top Heat Map). The standardized variable ratios represent the average distance from the annual hourly mean of the recorded hourly load and expressed as a multiple of annual hourly standard deviation. A ratio of 2.5 represents a distance of 2.5 standard deviations from the mean. Positive and negative values indicate directional bias either above or below the means, respectively. The plot is intended to illustrate aggregate loading of distribution system circuits by hour and month, and does not represent "at risk" load levels where distribution infrastructure capacity may be exceeded. As illustrated below, when looking at the distribution system in aggregate, a high concentration of peak circuit loads on SCE's system tend to occur on summer weekdays, as depicted by the red cells. Similarly, the weekend plot also shows the same relative pattern, though the intensity of the peaks are much lower on the weekends. Red cells indicate the periods when the distribution system would typically experience peak loads across all circuits. SCE also conducted a similar analysis by circuits within specific regions and included the monthly dispersion by region in Appendix A, Figure 15.

FIGURE 7: 2014 RECORDED VS. 2024 PROJECTED LOAD STANDARDIZED VARIABLE HEAT MAPS

2014 recorded load standardized variable heat map

Average of SV	Column La																							
Row Labels	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
WEEKDAYS	**(0.86)**	**(1.03)**	**(1.11)**	**(1.06)**	**(0.84)**	**(0.52)**	**(0.23)**	**(0.02)**	**0.17**	**0.34**	**0.48**	**0.60**	**0.74**	**0.86**	**0.93**	**0.95**	**0.96**	**1.00**	**0.95**	**0.87**	**0.67**	**0.33**	**(0.13)**	**(0.53)**
JAN	(1.02)	(1.19)	(1.28)	(1.28)	(1.14)	(0.80)	(0.39)	(0.25)	(0.15)	(0.09)	(0.06)	(0.05)	(0.05)	(0.03)	(0.04)	(0.05)	0.08	0.47	0.47	0.36	0.23	0.03	(0.31)	(0.58)
FEB	(1.04)	(1.20)	(1.29)	(1.31)	(1.16)	(0.80)	(0.41)	(0.25)	(0.18)	(0.12)	(0.09)	(0.08)	(0.07)	(0.06)	(0.07)	(0.08)	(0.04)	0.32	0.42	0.34	0.22	0.02	(0.32)	(0.70)
MAR	(1.18)	(1.30)	(1.35)	(1.27)	(1.01)	(0.59)	(0.39)	(0.28)	(0.20)	(0.13)	(0.10)	(0.08)	(0.05)	(0.05)	(0.06)	(0.08)	(0.10)	0.03	0.30	0.25	0.09	(0.19)	(0.58)	(0.92)
APR	(1.15)	(1.27)	(1.31)	(1.20)	(0.91)	(0.50)	(0.39)	(0.24)	(0.11)	(0.01)	0.07	0.13	0.21	0.26	0.30	0.30	0.26	0.23	0.44	0.44	0.26	(0.09)	(0.53)	(0.88)
MAY	(0.95)	(1.10)	(1.16)	(1.06)	(0.83)	(0.53)	(0.24)	(0.01)	0.21	0.40	0.56	0.69	0.85	0.98	1.08	1.10	1.04	0.92	0.87	0.90	0.70	0.30	(0.22)	(0.53)
JUN	(0.78)	(0.95)	(1.02)	(0.94)	(0.74)	(0.47)	(0.18)	0.08	0.31	0.52	0.70	0.87	1.08	1.26	1.40	1.45	1.39	1.25	1.03	1.02	0.88	0.49	(0.02)	(0.45)
JUL	(0.33)	(0.56)	(0.67)	(0.61)	(0.42)	(0.18)	0.16	0.50	0.83	1.17	1.47	1.76	2.06	2.31	2.48	2.55	2.48	2.29	1.97	1.82	1.62	1.16	0.58	0.06
AUG	(0.46)	(0.67)	(0.76)	(0.70)	(0.45)	(0.19)	0.10	0.41	0.72	1.01	1.35	1.65	1.96	2.20	2.38	2.42	2.32	2.10	1.82	1.73	1.44	0.95	0.37	(0.11)
SEP	(0.42)	(0.62)	(0.72)	(0.65)	(0.37)	(0.02)	0.23	0.54	0.85	1.17	1.48	1.79	2.11	2.36	2.53	2.55	2.41	2.18	2.07	1.92	1.55	1.01	0.39	(0.09)
OCT	(0.97)	(1.10)	(1.15)	(1.05)	(0.75)	(0.35)	(0.20)	(0.03)	0.15	0.33	0.47	0.63	0.83	0.98	1.08	1.07	0.98	1.03	0.98	0.80	0.53	0.12	(0.35)	(0.71)
NOV	(1.11)	(1.26)	(1.35)	(1.36)	(1.23)	(0.90)	(0.60)	(0.43)	(0.31)	(0.21)	(0.13)	(0.07)	(0.03)	0.02	0.04	0.05	0.23	0.47	0.41	0.27	0.13	(0.07)	(0.42)	(0.77)
DEC	(0.97)	(1.17)	(1.27)	(1.29)	(1.17)	(0.85)	(0.48)	(0.32)	(0.21)	(0.15)	(0.12)	(0.11)	(0.14)	(0.13)	(0.14)	(0.11)	0.26	0.57	0.55	0.46	0.35	0.17	(0.18)	(0.57)
WEEKENDS	**(0.88)**	**(1.07)**	**(1.19)**	**(1.22)**	**(1.18)**	**(1.09)**	**(0.96)**	**(0.76)**	**(0.55)**	**(0.36)**	**(0.20)**	**(0.07)**	**0.04**	**0.15**	**0.23**	**0.28**	**0.36**	**0.47**	**0.47**	**0.42**	**0.27**	**0.00**	**(0.37)**	**(0.71)**
JAN	(1.01)	(1.19)	(1.30)	(1.36)	(1.33)	(1.20)	(1.06)	(1.00)	(0.86)	(0.77)	(0.73)	(0.71)	(0.75)	(0.80)	(0.80)	(0.78)	(0.57)	(0.13)	(0.09)	(0.15)	(0.25)	(0.40)	(0.65)	(0.95)
FEB	(1.07)	(1.25)	(1.35)	(1.40)	(1.36)	(1.22)	(1.08)	(0.99)	(0.84)	(0.74)	(0.69)	(0.68)	(0.68)	(0.70)	(0.71)	(0.69)	(0.60)	(0.16)	(0.04)	(0.08)	(0.17)	(0.32)	(0.59)	(0.89)
MAR	(1.18)	(1.33)	(1.41)	(1.43)	(1.36)	(1.23)	(1.16)	(1.01)	(0.86)	(0.75)	(0.71)	(0.68)	(0.67)	(0.65)	(0.63)	(0.59)	(0.54)	(0.36)	(0.08)	(0.10)	(0.24)	(0.45)	(0.77)	(1.06)
APR	(1.22)	(1.35)	(1.42)	(1.41)	(1.32)	(1.24)	(1.14)	(0.98)	(0.85)	(0.77)	(0.74)	(0.73)	(0.72)	(0.71)	(0.69)	(0.65)	(0.60)	(0.53)	(0.19)	(0.15)	(0.27)	(0.51)	(0.84)	(1.13)
MAY	(0.94)	(1.12)	(1.22)	(1.24)	(1.19)	(1.17)	(0.99)	(0.75)	(0.54)	(0.35)	(0.21)	(0.07)	0.06	0.20	0.31	0.38	0.39	0.34	0.31	0.37	0.22	(0.08)	(0.48)	(0.83)
JUN	(0.79)	(0.98)	(1.10)	(1.13)	(1.09)	(1.08)	(0.89)	(0.64)	(0.39)	(0.17)	0.04	0.25	0.46	0.67	0.84	0.93	0.94	0.87	0.71	0.70	0.58	0.26	(0.19)	(0.58)
JUL	(0.39)	(0.64)	(0.79)	(0.85)	(0.83)	(0.83)	(0.60)	(0.26)	0.11	0.48	0.82	1.12	1.39	1.60	1.75	1.82	1.81	1.59	1.45	1.33	1.17	0.82	0.35	(0.09)
AUG	(0.40)	(0.64)	(0.79)	(0.85)	(0.82)	(0.79)	(0.63)	(0.32)	0.00	0.35	0.70	1.04	1.35	1.60	1.76	1.82	1.75	1.59	1.41	1.35	1.12	0.73	0.25	(0.19)
SEP	(0.54)	(0.76)	(0.90)	(0.95)	(0.89)	(0.90)	(0.68)	(0.35)	0.01	0.37	0.72	1.05	1.34	1.57	1.74	1.78	1.72	1.59	1.52	1.38	1.09	0.65	0.14	(0.29)
OCT	(0.96)	(1.13)	(1.23)	(1.24)	(1.17)	(1.03)	(0.97)	(0.75)	(0.54)	(0.34)	(0.16)	0.04	0.25	0.44	0.59	0.65	0.62	0.72	0.60	0.50	0.26	(0.08)	(0.49)	(0.82)
NOV	(1.13)	(1.30)	(1.41)	(1.45)	(1.42)	(1.29)	(1.18)	(1.07)	(0.90)	(0.77)	(0.68)	(0.63)	(0.60)	(0.58)	(0.55)	(0.52)	(0.28)	(0.02)	(0.04)	(0.13)	(0.25)	(0.42)	(0.70)	(1.00)
DEC	(0.94)	(1.15)	(1.28)	(1.34)	(1.32)	(1.20)	(1.05)	(0.97)	(0.83)	(0.75)	(0.73)	(0.75)	(0.77)	(0.78)	(0.78)	(0.72)	(0.27)	0.09	0.12	0.08	0.02	(0.12)	(0.39)	(0.72)
Grand Total	**(0.87)**	**(1.04)**	**(1.13)**	**(1.11)**	**(0.94)**	**(0.69)**	**(0.45)**	**(0.25)**	**(0.05)**	**0.12**	**0.27**	**0.40**	**0.53**	**0.64**	**0.71**	**0.74**	**0.77**	**0.83**	**0.80**	**0.73**	**0.55**	**0.23**	**(0.20)**	**(0.59)**

2024 projected load standardized variable heat map

Average of SV	Column La																							
Row Labels	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
WEEKDAYS	**(0.67)**	**(0.85)**	**(0.94)**	**(0.88)**	**(0.63)**	**(0.28)**	**(0.02)**	**0.03**	**(0.00)**	**(0.02)**	**(0.02)**	**0.03**	**0.16**	**0.34**	**0.56**	**0.77**	**1.02**	**1.27**	**1.31**	**1.24**	**1.03**	**0.65**	**0.14**	**(0.30)**
JAN	(0.85)	(1.03)	(1.13)	(1.14)	(0.98)	(0.59)	(0.15)	(0.03)	(0.17)	(0.32)	(0.43)	(0.50)	(0.51)	(0.42)	(0.30)	(0.13)	0.21	0.80	0.80	0.68	0.54	0.31	(0.06)	(0.47)
FEB	(0.87)	(1.05)	(1.16)	(1.17)	(1.00)	(0.61)	(0.17)	(0.06)	(0.22)	(0.34)	(0.41)	(0.46)	(0.46)	(0.36)	(0.28)	(0.17)	0.03	0.50	0.75	0.66	0.52	0.30	(0.08)	(0.50)
MAR	(1.02)	(1.15)	(1.20)	(1.11)	(0.82)	(0.35)	(0.17)	(0.27)	(0.43)	(0.56)	(0.66)	(0.73)	(0.74)	(0.69)	(0.57)	(0.38)	(0.16)	0.22	0.62	0.58	0.40	0.08	(0.35)	(0.72)
APR	(0.98)	(1.11)	(1.16)	(1.03)	(0.71)	(0.37)	(0.25)	(0.33)	(0.43)	(0.53)	(0.60)	(0.62)	(0.55)	(0.43)	(0.23)	(0.03)	0.17	0.39	0.77	0.78	0.58	0.19	(0.30)	(0.68)
MAY	(0.71)	(0.91)	(0.97)	(0.86)	(0.60)	(0.28)	(0.10)	(0.06)	(0.04)	(0.04)	(0.05)	0.00	0.14	0.32	0.57	0.81	1.00	1.13	1.23	1.31	1.09	0.65	0.08	(0.38)
JUN	(0.58)	(0.76)	(0.84)	(0.74)	(0.52)	(0.23)	(0.04)	0.02	0.05	0.07	0.09	0.16	0.34	0.57	0.85	1.10	1.28	1.38	1.32	1.38	1.24	0.81	0.25	(0.21)
JUL	(0.11)	(0.35)	(0.48)	(0.40)	(0.10)	0.18	0.42	0.45	0.57	0.71	0.85	1.06	1.37	1.69	2.07	2.29	2.45	2.51	2.48	2.24	2.07	1.57	0.88	0.47
AUG	(0.23)	(0.46)	(0.56)	(0.48)	(0.20)	0.09	0.32	0.42	0.52	0.64	0.79	1.01	1.32	1.63	1.97	2.21	2.35	2.39	2.24	2.16	1.86	1.32	0.60	0.16
SEP	(0.16)	(0.39)	(0.49)	(0.41)	(0.09)	0.30	0.52	0.62	0.72	0.85	1.01	1.23	1.57	1.92	2.25	2.49	2.61	2.61	2.56	2.39	2.00	1.41	0.74	0.20
OCT	(0.76)	(0.92)	(0.97)	(0.86)	(0.52)	(0.06)	0.09	0.05	0.00	(0.01)	0.00	0.09	0.31	0.56	0.81	1.03	1.20	1.44	1.38	1.18	0.89	0.44	(0.08)	(0.48)
NOV	(0.93)	(1.11)	(1.20)	(1.21)	(1.06)	(0.70)	(0.37)	(0.31)	(0.43)	(0.50)	(0.53)	(0.55)	(0.52)	(0.38)	(0.21)	0.02	0.48	0.81	0.74	0.60	0.44	0.21	(0.17)	(0.56)
DEC	(0.80)	(1.02)	(1.13)	(1.16)	(1.01)	(0.66)	(0.25)	(0.12)	(0.22)	(0.34)	(0.43)	(0.49)	(0.52)	(0.46)	(0.36)	(0.15)	0.48	0.89	0.87	0.76	0.64	0.44	0.07	(0.36)
WEEKENDS	**(0.69)**	**(0.90)**	**(1.03)**	**(1.07)**	**(1.02)**	**(0.93)**	**(0.84)**	**(0.80)**	**(0.80)**	**(0.79)**	**(0.78)**	**(0.72)**	**(0.62)**	**(0.45)**	**(0.23)**	**0.02**	**0.35**	**0.68**	**0.77**	**0.73**	**0.57**	**0.28**	**(0.13)**	**(0.51)**
JAN	(0.85)	(1.04)	(1.17)	(1.24)	(1.20)	(1.06)	(0.90)	(0.88)	(0.90)	(1.10)	(1.19)	(1.25)	(1.30)	(1.29)	(1.18)	(0.98)	(0.51)	0.14	0.18	0.11	[illegible]	(0.16)	(0.44)	(0.75)
FEB	(0.92)	(1.11)	(1.23)	(1.28)	(1.24)	(1.08)	(0.93)	(0.90)	(0.90)	(0.92)	(0.97)	(1.00)	(1.03)	(1.01)	(0.98)	(0.86)	(0.59)	0.05	0.22	0.18	0.08	(0.09)	(0.38)	(0.71)
MAR	(1.02)	(1.18)	(1.28)	(1.30)	(1.23)	(1.07)	(1.02)	(1.08)	(1.16)	(1.27)	(1.38)	(1.47)	(1.50)	(1.44)	(1.25)	(1.00)	(0.68)	(0.22)	0.20	0.17	0.02	(0.22)	(0.57)	(0.89)
APR	(1.06)	(1.21)	(1.28)	(1.27)	(1.18)	(1.09)	(1.10)	(1.16)	(1.23)	(1.34)	(1.46)	(1.53)	(1.57)	(1.52)	(1.36)	(1.10)	(0.81)	(0.46)	0.07	0.12	(0.01)	(0.27)	(0.65)	(0.96)
MAY	(0.74)	(0.93)	(1.05)	(1.07)	(1.01)	(1.01)	(0.94)	(0.88)	(0.85)	(0.86)	(0.86)	(0.79)	(0.66)	(0.49)	(0.23)	0.03	0.26	0.46	0.59	0.70	0.54	0.20	(0.24)	(0.62)
JUN	(0.59)	(0.80)	(0.95)	(0.99)	(0.97)	(0.94)	(0.87)	(0.81)	(0.79)	(0.77)	(0.76)	(0.64)	(0.45)	(0.18)	0.15	0.47	0.74	0.94	0.95	1.07	0.93	0.54	0.05	(0.47)
JUL	(0.18)	(0.44)	(0.62)	(0.68)	(0.65)	(0.66)	(0.53)	(0.40)	(0.25)	(0.08)	0.10	0.33	0.60	0.89	1.20	1.48	1.70	1.84	1.76	1.69	1.52	1.14	0.63	0.15
AUG	(0.15)	(0.43)	(0.60)	(0.66)	(0.62)	(0.59)	(0.52)	(0.41)	(0.28)	(0.10)	0.11	0.38	0.68	1.00	1.30	1.57	1.74	1.83	1.79	1.75	1.50	1.08	0.55	0.07
SEP	(0.30)	(0.54)	(0.70)	(0.75)	(0.69)	(0.59)	(0.51)	(0.41)	(0.28)	(0.12)	0.08	0.33	0.64	0.97	1.29	1.61	1.83	1.95	1.95	1.81	1.49	1.01	0.45	(0.02)
OCT	(0.70)	(0.94)	(1.06)	(1.07)	(0.99)	(0.83)	(0.79)	(0.78)	(0.76)	(0.68)	(0.57)	(0.44)	(0.22)	0.08	0.37	0.62	0.82	1.08	1.05	0.85	0.58	0.21	(0.23)	(0.61)
NOV	(0.96)	(1.14)	(1.26)	(1.31)	(1.27)	(1.14)	(1.07)	(1.04)	(1.16)	(1.21)	(1.27)	(1.30)	(1.25)	(1.11)	(0.92)	(0.64)	(0.10)	0.27	0.24	0.14	[illegible]	(0.10)	(0.49)	(0.83)
DEC	(0.78)	(1.00)	(1.14)	(1.21)	(1.19)	(1.05)	(0.89)	(0.85)	(0.92)	(1.01)	(1.11)	(1.18)	(1.22)	(1.18)	(1.08)	(0.83)	(0.11)	0.35	0.38	0.34	0.26	0.12	(0.18)	(0.55)
Grand Total	**(0.68)**	**(0.87)**	**(0.96)**	**(0.93)**	**(0.75)**	**(0.48)**	**(0.27)**	**(0.22)**	**(0.25)**	**(0.26)**	**(0.26)**	**(0.20)**	**(0.08)**	**0.10**	**0.32**	**0.54**	**0.82**	**1.09**	**1.15**	**1.08**	**0.89**	**0.53**	**0.06**	**(0.37)**

It is essential to remember that when determining time of use periods, a test year in the future needs to be selected for doing such load analysis. The future test year ensures that time of use periods are forward looking and should be set sufficiently stable for a period of time consistent with behavioral and investment choices customers may make to accommodate such TOU periods. While the plot depicted below is based on recorded circuit load data for the year 2014, a similar analysis can be performed for circuit loads in an appropriate test year in the future when determining future time of use periods. When using distribution system cost drivers to inform time of use periods, it is important to capture how the future deployment on DERs, specifically distributed generation (DG) will impact the frequency, magnitude and timing of distribution system loads. As an example, SCE has also included the load plot for the year 2024 that includes the impact of DG penetration on the distribution system (Figure 7 – Bottom Heat Map). The trend has been forecasted for each circuit based on the existing circuit DG saturation scaled pro-rata to the overall growth rate projected for DG installations on SCE's system.

<u>Peak Load Risk Factor (PLRF) – Time of Use Determination for Distribution Costs</u>

For distribution system planners, the primary trigger that initiates a deeper look into circuit loading occurs when normal projected load reaches 73 percent of the average PLL of circuits connected to a single substation, this 73 percent threshold acts as a proxy for the potential of load at risk on distribution circuits.[7] Distribution

Planning criteria states that maximum criteria projected loading on any distribution circuit should not exceed a typical value of 550 amps, the average normal projected load should not exceed 400 amps (400/550 = 73 percent). The 73 percent as applied to the average PLL of the circuits connected to a single substation is important because it identifies the load points at which Distribution Planning will conduct a capacity review of a substation or its associated circuits. The PLRF analysis is conducted using a two-step approach. First, all circuit load points at a distribution substation that fall below the threshold of 73 percent of average circuit PLL are set to zero. Secondly, the remaining load points are aggregated for all circuits and a relative ratio is determined for these hourly load values. This ratio defines the percentage load in an hour to the sum of the total peak load for each hour in the year, given the 73 percent threshold. This relative ratio is called the Peak Load Risk Factor (PLRF). For substations, the flag for substation loading occurs at 90 percent of PLL. Similarly, this serves as a proxy threshold for distribution system substations.

The plot below illustrates the general dispersion of PLRF ratios for the year 2014 (Figure 8 – Top Heat Map). The values shown on the heat map below are derived by calculating the standardized variable of the recorded PLRF load values for all circuits by hour. As evident from the illustration below, with the application of the PLRF criteria, the peaks tend to be concentrated in the summer, similar to the load plot above. Red cells indicate the periods when peak loads would typically be experienced across all circuits on the distribution system. As previously mentioned in this section, assuming a future projection of DG on distribution circuits, SCE has also included the standardized variable plot for the year 2024 (Figure 8 – Bottom Heat Map).

FIGURE 8: 2014 RECORDED VS. 2024 PROJECTED PLRF LOAD STANDARDIZED VARIABLE HEAT MAPS

2014 Recorded PLRF Load Standardized Variable Heat Map

Average of SV PLRF	Column Labels																							
Row Labels	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
WEEKDAYS	(0.38)	(0.38)	(0.40)	(0.40)	(0.38)	(0.32)	(0.19)	(0.04)	0.10	0.28	0.41	0.51	0.71	0.82	0.86	0.76	0.55	0.39	0.30	0.22	0.03	(0.19)	(0.30)	(0.34)
JAN	(0.36)	(0.36)	(0.36)	(0.38)	(0.38)	(0.37)	(0.32)	(0.22)	(0.15)	(0.10)	(0.08)	(0.08)	(0.10)	(0.05)	(0.11)	(0.17)	(0.22)	(0.12)	(0.09)	(0.14)	(0.18)	(0.26)	(0.32)	(0.34)
FEB	(0.40)	(0.40)	(0.42)	(0.42)	(0.42)	(0.39)	(0.33)	(0.23)	(0.14)	(0.11)	(0.07)	(0.05)	(0.06)	(0.07)	(0.12)	(0.16)	(0.26)	(0.18)	(0.09)	(0.12)	(0.18)	(0.27)	(0.35)	(0.37)
MAR	(0.44)	(0.44)	(0.46)	(0.45)	(0.43)	(0.35)	(0.26)	(0.17)	(0.12)	(0.05)	(0.04)	(0.01)	0.01	(0.05)	(0.12)	(0.20)	(0.31)	(0.28)	(0.14)	(0.16)	(0.23)	(0.32)	(0.38)	(0.40)
APR	(0.41)	(0.41)	(0.44)	(0.44)	(0.41)	(0.38)	(0.25)	(0.15)	(0.06)	0.01	0.08	0.09	0.16	0.12	0.09	(0.02)	(0.17)	(0.24)	(0.12)	(0.12)	(0.22)	(0.31)	(0.36)	(0.39)
MAY	(0.41)	(0.42)	(0.43)	(0.42)	(0.38)	(0.33)	(0.09)	0.11	0.31	0.58	0.75	0.92	1.18	1.32	1.40	1.31	1.04	0.68	0.43	0.43	0.19	(0.13)	(0.31)	(0.37)
JUN	(0.36)	(0.36)	(0.36)	(0.35)	(0.33)	(0.24)	(0.08)	0.05	0.14	0.35	0.41	0.43	0.58	0.64	0.66	0.53	0.31	0.15	0.07	0.11	0.04	(0.11)	(0.22)	(0.31)
JUL	(0.31)	(0.31)	(0.34)	(0.32)	(0.28)	(0.20)	0.01	0.22	0.47	0.82	1.07	1.35	1.82	2.24	2.54	2.57	2.18	1.58	0.90	0.67	0.43	0.03	(0.17)	(0.25)
AUG	(0.32)	(0.32)	(0.34)	(0.35)	(0.31)	(0.23)	(0.04)	0.17	0.41	0.72	0.91	1.10	1.50	1.72	1.95	1.79	1.38	0.81	0.44	0.44	0.14	(0.14)	(0.22)	(0.28)
SEP	(0.34)	(0.35)	(0.38)	(0.38)	(0.34)	(0.24)	(0.04)	0.25	0.61	1.10	1.58	2.10	2.86	3.34	3.51	3.28	2.69	1.98	1.94	1.60	0.80	0.06	(0.22)	(0.31)
OCT	(0.38)	(0.39)	(0.41)	(0.39)	(0.38)	(0.27)	(0.16)	(0.05)	0.06	0.22	0.36	0.42	0.61	0.59	0.54	0.36	0.15	0.20	0.20	0.08	(0.13)	(0.27)	(0.33)	(0.36)
NOV	(0.38)	(0.39)	(0.39)	(0.40)	(0.41)	(0.39)	(0.33)	(0.21)	(0.13)	(0.07)	(0.04)	(0.01)	0.01	0.04	0.02	(0.08)	(0.12)	(0.04)	(0.06)	(0.15)	(0.23)	(0.27)	(0.33)	(0.34)
DEC	(0.42)	(0.43)	(0.43)	(0.46)	(0.45)	(0.43)	(0.37)	(0.31)	(0.23)	(0.17)	(0.14)	(0.15)	(0.19)	(0.17)	(0.20)	(0.24)	(0.19)	0.02	0.06	(0.01)	(0.10)	(0.24)	(0.35)	(0.38)
WEEKENDS	(0.37)	(0.38)	(0.40)	(0.42)	(0.42)	(0.42)	(0.41)	(0.40)	(0.39)	(0.37)	(0.33)	(0.27)	(0.15)	(0.03)	0.09	0.13	0.08	(0.01)	(0.07)	(0.12)	(0.21)	(0.31)	(0.37)	(0.39)
JAN	(0.35)	(0.35)	(0.35)	(0.37)	(0.38)	(0.38)	(0.39)	(0.38)	(0.36)	(0.35)	(0.34)	(0.35)	(0.37)	(0.35)	(0.35)	(0.35)	(0.34)	(0.27)	(0.24)	(0.25)	(0.28)	(0.32)	(0.35)	(0.37)
FEB	(0.41)	(0.42)	(0.42)	(0.43)	(0.43)	(0.43)	(0.43)	(0.42)	(0.40)	(0.39)	(0.42)	(0.41)	(0.41)	(0.42)	(0.43)	(0.42)	(0.42)	(0.36)	(0.31)	(0.30)	(0.34)	(0.36)	(0.41)	(0.42)
MAR	(0.43)	(0.43)	(0.45)	(0.46)	(0.45)	(0.44)	(0.43)	(0.44)	(0.44)	(0.44)	(0.44)	(0.43)	(0.43)	(0.43)	(0.44)	(0.45)	(0.44)	(0.41)	(0.33)	(0.34)	(0.37)	(0.42)	(0.43)	(0.44)
APR	(0.40)	(0.39)	(0.42)	(0.44)	(0.44)	(0.43)	(0.40)	(0.40)	(0.39)	(0.39)	(0.39)	(0.40)	(0.40)	(0.42)	(0.42)	(0.43)	(0.45)	(0.42)	(0.34)	(0.35)	(0.35)	(0.35)	(0.39)	(0.41)
MAY	(0.37)	(0.40)	(0.41)	(0.42)	(0.42)	(0.43)	(0.41)	(0.40)	(0.37)	(0.38)	(0.34)	(0.32)	(0.28)	(0.24)	(0.20)	(0.20)	(0.20)	(0.25)	(0.25)	(0.20)	(0.26)	(0.35)	(0.38)	(0.40)
JUN	(0.36)	(0.37)	(0.40)	(0.41)	(0.40)	(0.40)	(0.39)	(0.42)	(0.43)	(0.40)	(0.38)	(0.34)	(0.28)	(0.20)	(0.14)	(0.10)	(0.11)	(0.13)	(0.16)	(0.16)	(0.20)	(0.28)	(0.35)	(0.37)
JUL	(0.33)	(0.34)	(0.37)	(0.38)	(0.38)	(0.37)	(0.35)	(0.38)	(0.39)	(0.34)	(0.25)	(0.08)	0.14	0.42	0.74	0.90	0.84	0.58	0.26	0.09	0.01	(0.20)	(0.33)	(0.35)
AUG	(0.35)	(0.38)	(0.41)	(0.43)	(0.44)	(0.42)	(0.41)	(0.40)	(0.39)	(0.37)	(0.31)	(0.22)	(0.01)	0.26	0.53	0.66	0.52	0.23	0.00	(0.00)	(0.13)	(0.24)	(0.31)	(0.35)
SEP	(0.35)	(0.37)	(0.41)	(0.42)	(0.42)	(0.43)	(0.43)	(0.41)	(0.41)	(0.31)	(0.06)	0.42	1.28	2.04	2.64	2.84	2.45	1.58	1.11	0.83	0.31	(0.17)	(0.33)	(0.37)
OCT	(0.37)	(0.38)	(0.40)	(0.41)	(0.41)	(0.42)	(0.40)	(0.36)	(0.36)	(0.34)	(0.34)	(0.35)	(0.28)	(0.12)	0.01	0.02	(0.07)	(0.05)	(0.04)	(0.14)	(0.23)	(0.34)	(0.36)	(0.39)
NOV	(0.35)	(0.36)	(0.37)	(0.40)	(0.40)	(0.41)	(0.41)	(0.38)	(0.35)	(0.34)	(0.32)	(0.33)	(0.35)	(0.35)	(0.35)	(0.36)	(0.35)	(0.32)	(0.30)	(0.33)	(0.36)	(0.39)	(0.41)	(0.40)
DEC	(0.43)	(0.43)	(0.43)	(0.44)	(0.45)	(0.44)	(0.45)	(0.42)	(0.39)	(0.38)	(0.38)	(0.38)	(0.41)	(0.40)	(0.42)	(0.41)	(0.37)	(0.21)	(0.17)	(0.20)	(0.25)	(0.31)	(0.41)	(0.41)
Grand Total	(0.38)	(0.38)	(0.40)	(0.40)	(0.39)	(0.35)	(0.25)	(0.15)	(0.05)	0.08	0.18	0.28	0.44	0.56	0.62	0.57	0.41	0.27	0.19	0.12	(0.04)	(0.22)	(0.32)	(0.36)

2024 Recorded PLRF Load Standardized Variable Heat Map

Average of SV PLRF	Column Labels																							
Row Labels	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
WEEKDAYS	(0.41)	(0.41)	(0.43)	(0.43)	(0.40)	(0.33)	(0.17)	(0.02)	0.12	0.28	0.38	0.45	0.61	0.68	0.72	0.67	0.58	0.60	0.57	0.47	0.18	(0.13)	(0.30)	(0.36)
JAN	(0.39)	(0.39)	(0.39)	(0.41)	(0.41)	(0.40)	(0.33)	(0.21)	(0.13)	(0.10)	(0.09)	(0.09)	(0.12)	(0.07)	(0.13)	(0.18)	(0.22)	(0.00)	0.02	(0.08)	(0.17)	(0.26)	(0.34)	(0.37)
FEB	(0.43)	(0.43)	(0.45)	(0.46)	(0.45)	(0.42)	(0.34)	(0.22)	(0.13)	(0.12)	(0.07)	(0.07)	(0.08)	(0.07)	(0.10)	(0.17)	(0.27)	(0.13)	(0.00)	(0.07)	(0.16)	(0.28)	(0.37)	(0.41)
MAR	(0.47)	(0.48)	(0.50)	(0.49)	(0.46)	(0.37)	(0.26)	(0.16)	(0.11)	(0.07)	(0.07)	(0.05)	(0.02)	(0.08)	(0.14)	(0.23)	(0.33)	(0.27)	(0.07)	(0.11)	(0.21)	(0.32)	(0.41)	(0.44)
APR	(0.44)	(0.44)	(0.48)	(0.48)	(0.45)	(0.40)	(0.25)	(0.14)	(0.07)	(0.01)	0.05	0.06	0.13	0.10	0.08	(0.03)	(0.17)	(0.22)	(0.05)	(0.03)	(0.18)	(0.31)	(0.38)	(0.42)
MAY	(0.45)	(0.46)	(0.47)	(0.46)	(0.41)	(0.34)	(0.06)	0.13	0.33	0.58	0.70	0.83	1.05	1.15	1.24	1.20	1.04	0.84	0.65	0.69	0.36	(0.05)	(0.31)	(0.39)
JUN	(0.39)	(0.39)	(0.38)	(0.38)	(0.35)	(0.23)	(0.05)	0.08	0.16	0.35	0.41	0.40	0.53	0.57	0.60	0.47	0.32	0.27	0.21	0.28	0.16	(0.07)	(0.21)	(0.32)
JUL	(0.32)	(0.33)	(0.36)	(0.34)	(0.30)	(0.18)	0.06	0.26	0.50	0.82	1.01	1.21	1.54	1.83	2.05	2.16	2.12	2.03	1.61	1.31	0.89	0.23	(0.12)	(0.24)
AUG	(0.33)	(0.33)	(0.35)	(0.36)	(0.31)	(0.21)	0.03	0.23	0.47	0.76	0.89	1.01	1.32	1.46	1.63	1.61	1.47	1.21	0.97	0.93	0.47	(0.04)	(0.21)	(0.27)
SEP	(0.36)	(0.38)	(0.41)	(0.41)	(0.36)	(0.23)	(0.01)	0.31	0.67	1.12	1.48	1.86	2.46	2.82	3.01	3.07	2.92	2.74	2.81	2.40	1.29	0.24	(0.19)	(0.32)
OCT	(0.41)	(0.42)	(0.44)	(0.43)	(0.40)	(0.28)	(0.15)	(0.01)	0.08	0.24	0.37	0.41	0.59	0.57	0.52	0.39	0.22	0.39	0.38	0.19	(0.09)	(0.28)	(0.35)	(0.39)
NOV	(0.41)	(0.42)	(0.43)	(0.44)	(0.45)	(0.42)	(0.36)	(0.22)	(0.13)	(0.07)	(0.04)	(0.02)	0.01	0.04	0.04	(0.06)	(0.10)	0.07	0.04	(0.12)	(0.23)	(0.28)	(0.36)	(0.37)
DEC	(0.46)	(0.46)	(0.47)	(0.50)	(0.49)	(0.47)	(0.39)	(0.33)	(0.24)	(0.19)	(0.16)	(0.18)	(0.23)	(0.20)	(0.22)	(0.26)	(0.18)	0.18	0.21	0.12	(0.02)	(0.22)	(0.36)	(0.41)
WEEKENDS	(0.40)	(0.41)	(0.44)	(0.45)	(0.45)	(0.45)	(0.44)	(0.43)	(0.42)	(0.40)	(0.38)	(0.34)	(0.28)	(0.19)	(0.10)	(0.02)	0.05	0.11	0.08	0.01	(0.13)	(0.30)	(0.39)	(0.42)
JAN	(0.38)	(0.38)	(0.39)	(0.41)	(0.41)	(0.42)	(0.42)	(0.42)	(0.39)	(0.38)	(0.38)	(0.38)	(0.40)	(0.39)	(0.38)	(0.39)	(0.37)	(0.27)	(0.23)	(0.25)	(0.30)	(0.34)	(0.38)	(0.40)
FEB	(0.45)	(0.46)	(0.46)	(0.47)	(0.47)	(0.47)	(0.46)	(0.46)	(0.43)	(0.43)	(0.46)	(0.44)	(0.45)	(0.46)	(0.46)	(0.45)	(0.45)	(0.37)	(0.31)	(0.31)	(0.35)	(0.38)	(0.45)	(0.45)
MAR	(0.46)	(0.47)	(0.49)	(0.50)	(0.49)	(0.48)	(0.47)	(0.48)	(0.48)	(0.48)	(0.49)	(0.47)	(0.48)	(0.47)	(0.48)	(0.48)	(0.48)	(0.45)	(0.33)	(0.33)	(0.38)	(0.43)	(0.46)	(0.48)
APR	(0.43)	(0.43)	(0.45)	(0.47)	(0.48)	(0.46)	(0.44)	(0.44)	(0.42)	(0.43)	(0.43)	(0.45)	(0.45)	(0.47)	(0.46)	(0.47)	(0.49)	(0.45)	(0.35)	(0.38)	(0.38)	(0.38)	(0.43)	(0.44)
MAY	(0.40)	(0.43)	(0.44)	(0.46)	(0.46)	(0.46)	(0.44)	(0.44)	(0.40)	(0.41)	(0.38)	(0.37)	(0.33)	(0.30)	(0.26)	(0.25)	(0.23)	(0.22)	(0.21)	(0.14)	(0.22)	(0.36)	(0.41)	(0.44)
JUN	(0.39)	(0.40)	(0.43)	(0.44)	(0.43)	(0.43)	(0.42)	(0.45)	(0.47)	(0.44)	(0.43)	(0.39)	(0.34)	(0.29)	(0.24)	(0.21)	(0.14)	(0.07)	(0.07)	(0.02)	(0.10)	(0.25)	(0.35)	(0.39)
JUL	(0.35)	(0.36)	(0.40)	(0.42)	(0.41)	(0.40)	(0.38)	(0.41)	(0.43)	(0.38)	(0.31)	(0.22)	(0.08)	0.08	0.28	0.52	0.70	0.78	0.71	0.50	0.28	(0.08)	(0.30)	(0.35)
AUG	(0.36)	(0.39)	(0.43)	(0.46)	(0.46)	(0.44)	(0.43)	(0.42)	(0.42)	(0.39)	(0.34)	(0.28)	(0.14)	0.01	0.20	0.40	0.47	0.54	0.35	0.30	0.06	(0.18)	(0.29)	(0.35)
SEP	(0.38)	(0.40)	(0.44)	(0.46)	(0.46)	(0.46)	(0.46)	(0.45)	(0.44)	(0.36)	(0.17)	0.10	0.57	1.07	1.58	2.10	2.48	2.31	1.89	1.45	0.65	(0.07)	(0.32)	(0.40)
OCT	(0.40)	(0.41)	(0.44)	(0.44)	(0.45)	(0.45)	(0.43)	(0.38)	(0.39)	(0.36)	(0.37)	(0.39)	(0.33)	(0.19)	(0.09)	(0.06)	(0.03)	0.10	0.08	(0.09)	(0.20)	(0.36)	(0.39)	(0.42)
NOV	(0.38)	(0.39)	(0.40)	(0.43)	(0.44)	(0.45)	(0.44)	(0.41)	(0.39)	(0.37)	(0.35)	(0.36)	(0.39)	(0.38)	(0.38)	(0.39)	(0.38)	(0.31)	(0.30)	(0.35)	(0.38)	(0.42)	(0.44)	(0.43)
DEC	(0.47)	(0.46)	(0.47)	(0.48)	(0.49)	(0.47)	(0.48)	(0.46)	(0.43)	(0.42)	(0.41)	(0.43)	(0.45)	(0.43)	(0.45)	(0.45)	(0.40)	(0.17)	(0.12)	(0.15)	(0.22)	(0.32)	(0.44)	(0.44)
Grand Total	(0.40)	(0.41)	(0.43)	(0.44)	(0.42)	(0.37)	(0.26)	(0.15)	(0.05)	0.07	0.15	0.21	0.34	0.42	0.47	0.46	0.41	0.45	0.42	0.33	0.08	(0.19)	(0.33)	(0.38)

In addition to the standardized variable plot of the specific PLRF load values for the recorded year 2014, SCE has converted these load values into percentage allocation factors that form the basis of the allocation of distribution peak load variable marginal costs to individual hours of the year (Figure 9). The percentage represented in each cell is the *sum* of the individual hourly PLRF percentages for each hour in a given month.

This grouping of percentages by hour and month would be the method of allocating the peak load variable distribution marginal costs to time periods, the results of which would in turn, help inform the definition of TOU periods. Although this is a deterministic approach, it helps capture the intent of the amplitude and frequency of risk for each hour where a peak load risk is experienced in the year. Such a deterministic approach we believe is appropriate when reviewing distribution system loads as it helps capture the amplitude and frequency of load at risk while accounting for the diversity of load dispersion on distribution circuits. A refinement to such an approach would be a probabilistic model that simulates a similar construct on each circuit which can then be aggregated to summarize a relative probability distribution across each hour of the year. While there appears to be minimal differences in the intensity of the conditional formatting of the heat map between the PLRF percentage plot illustrated below and the PLRF load standardized variable plot (distance from the mean measured as a multiple of standard deviation of the data set) illustrated above, it can be concluded that distribution system peak load mapping across the 8,760 hours of the year can be used to inform time of use period determination as well as be the basis of allocating peak load variable distribution capacity marginal costs. Again, in order to appropriately define time of use periods, an appropriate future test year should be considered that sufficiently represents the duration for which such TOU periods will be defined. When using distribution system cost drivers to inform time of use periods, it is important to capture how the future deployment on DERs, specifically DG, tends to shift peak load on distribution circuits to later hours of the day in the form a circuit specific net load curve similar to the duck curve phenomena observed at CAISO system level load.[8]

FIGURE 9: 2014 RECOREDED VS. 2024 PROJECTED PLRF LOAD PERCENTAGE HEAT MAPS

2014 Recorded PLRF Load Percentage Heat Map

Sum of PLRF — Column Labels

Row Labels	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
WEEKDAYS	**0.96%**	**0.94%**	**0.87%**	**0.85%**	**0.97%**	**1.27%**	**1.93%**	**2.67%**	**3.41%**	**4.32%**	**4.96%**	**5.52%**	**6.51%**	**7.06%**	**7.28%**	**6.76%**	**5.70%**	**4.88%**	**4.42%**	**4.03%**	**3.04%**	**1.94%**	**1.37%**	**1.14%**
JAN	0.09%	0.09%	0.09%	0.08%	0.08%	0.09%	0.11%	0.15%	0.18%	0.21%	0.21%	0.22%	0.21%	0.23%	0.20%	0.17%	0.15%	0.20%	0.21%	0.19%	0.17%	0.13%	0.11%	0.10%
FEB	0.06%	0.06%	0.06%	0.05%	0.06%	0.07%	0.09%	0.13%	0.16%	0.17%	0.19%	0.20%	0.19%	0.19%	0.17%	0.15%	0.12%	0.15%	0.18%	0.17%	0.15%	0.11%	0.08%	0.07%
MAR	0.05%	0.05%	0.05%	0.05%	0.06%	0.09%	0.13%	0.17%	0.19%	0.22%	0.22%	0.23%	0.25%	0.22%	0.19%	0.16%	0.11%	0.12%	0.18%	0.17%	0.14%	0.11%	0.08%	0.07%
APR	0.07%	0.07%	0.06%	0.06%	0.07%	0.08%	0.14%	0.18%	0.22%	0.26%	0.28%	0.29%	0.32%	0.31%	0.29%	0.24%	0.18%	0.14%	0.20%	0.20%	0.15%	0.11%	0.09%	0.08%
MAY	0.07%	0.06%	0.06%	0.06%	0.08%	0.10%	0.20%	0.28%	0.37%	0.48%	0.56%	0.63%	0.74%	0.80%	0.83%	0.80%	0.68%	0.53%	0.42%	0.42%	0.32%	0.18%	0.11%	0.08%
JUN	0.09%	0.09%	0.09%	0.09%	0.10%	0.14%	0.21%	0.26%	0.30%	0.39%	0.42%	0.42%	0.49%	0.51%	0.52%	0.46%	0.37%	0.30%	0.27%	0.29%	0.26%	0.19%	0.15%	0.11%
JUL	0.11%	0.11%	0.10%	0.11%	0.13%	0.16%	0.26%	0.35%	0.46%	0.62%	0.73%	0.85%	1.06%	1.25%	1.38%	1.40%	1.22%	0.95%	0.65%	0.55%	0.44%	0.26%	0.18%	0.14%
AUG	0.10%	0.11%	0.10%	0.09%	0.11%	0.14%	0.22%	0.31%	0.42%	0.54%	0.63%	0.71%	0.88%	0.97%	1.07%	1.00%	0.83%	0.58%	0.43%	0.43%	0.30%	0.18%	0.15%	0.12%
SEP	0.09%	0.09%	0.08%	0.08%	0.10%	0.14%	0.22%	0.34%	0.50%	0.71%	0.91%	1.13%	1.45%	1.66%	1.73%	1.63%	1.38%	1.08%	1.06%	0.92%	0.58%	0.26%	0.15%	0.11%
OCT	0.09%	0.08%	0.07%	0.08%	0.09%	0.14%	0.19%	0.24%	0.29%	0.37%	0.43%	0.46%	0.54%	0.54%	0.51%	0.43%	0.33%	0.36%	0.36%	0.30%	0.20%	0.14%	0.11%	0.10%
NOV	0.07%	0.06%	0.06%	0.06%	0.06%	0.06%	0.09%	0.13%	0.16%	0.18%	0.19%	0.20%	0.21%	0.22%	0.21%	0.18%	0.16%	0.19%	0.19%	0.15%	0.12%	0.11%	0.09%	0.08%
DEC	0.06%	0.06%	0.06%	0.05%	0.05%	0.06%	0.09%	0.11%	0.15%	0.18%	0.19%	0.19%	0.17%	0.18%	0.16%	0.14%	0.16%	0.26%	0.28%	0.25%	0.21%	0.15%	0.10%	0.08%
WEEKENDS	**0.43%**	**0.41%**	**0.37%**	**0.33%**	**0.33%**	**0.34%**	**0.36%**	**0.37%**	**0.39%**	**0.44%**	**0.53%**	**0.68%**	**0.93%**	**1.22%**	**1.48%**	**1.57%**	**1.46%**	**1.25%**	**1.12%**	**1.01%**	**0.81%**	**0.57%**	**0.43%**	**0.40%**
JAN	0.04%	0.04%	0.04%	0.03%	0.03%	0.03%	0.03%	0.03%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.05%	0.06%	0.06%	0.05%	0.04%	0.04%	0.04%
FEB	0.03%	0.03%	0.03%	0.02%	0.02%	0.02%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.02%	0.03%	0.03%	0.04%	0.05%	0.05%	0.04%	0.04%	0.03%	0.03%
MAR	0.03%	0.03%	0.02%	0.02%	0.02%	0.03%	0.03%	0.03%	0.03%	0.02%	0.02%	0.03%	0.03%	0.03%	0.03%	0.02%	0.02%	0.03%	0.05%	0.05%	0.04%	0.03%	0.03%	0.02%
APR	0.03%	0.03%	0.02%	0.02%	0.02%	0.02%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.02%	0.02%	0.02%	0.02%	0.02%	0.04%	0.03%	0.03%	0.03%	0.03%	0.03%
MAY	0.04%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.04%	0.04%	0.04%	0.05%	0.06%	0.07%	0.07%	0.07%	0.07%	0.06%	0.06%	0.07%	0.06%	0.04%	0.04%	0.03%
JUN	0.04%	0.04%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.02%	0.03%	0.03%	0.04%	0.05%	0.07%	0.08%	0.08%	0.08%	0.08%	0.07%	0.07%	0.07%	0.05%	0.04%	0.04%
JUL	0.04%	0.04%	0.04%	0.03%	0.03%	0.04%	0.04%	0.03%	0.03%	0.04%	0.06%	0.09%	0.13%	0.18%	0.24%	0.27%	0.26%	0.21%	0.15%	0.12%	0.10%	0.07%	0.04%	0.04%
AUG	0.04%	0.04%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.04%	0.05%	0.07%	0.11%	0.17%	0.22%	0.25%	0.22%	0.16%	0.11%	0.11%	0.09%	0.06%	0.05%	0.04%
SEP	0.04%	0.04%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.05%	0.09%	0.18%	0.33%	0.47%	0.58%	0.62%	0.55%	0.39%	0.30%	0.25%	0.16%	0.07%	0.04%	0.03%
OCT	0.03%	0.03%	0.03%	0.03%	0.02%	0.02%	0.03%	0.03%	0.03%	0.04%	0.04%	0.04%	0.05%	0.07%	0.09%	0.09%	0.08%	0.08%	0.08%	0.07%	0.05%	0.04%	0.03%	0.03%
NOV	0.05%	0.05%	0.05%	0.04%	0.04%	0.04%	0.04%	0.05%	0.05%	0.06%	0.06%	0.06%	0.05%	0.05%	0.05%	0.05%	0.05%	0.06%	0.07%	0.06%	0.05%	0.04%	0.04%	0.04%
DEC	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.04%	0.06%	0.07%	0.07%	0.06%	0.05%	0.03%	0.03%
Grand Total	**1.39%**	**1.35%**	**1.23%**	**1.19%**	**1.30%**	**1.60%**	**2.29%**	**3.03%**	**3.80%**	**4.76%**	**5.49%**	**6.20%**	**7.43%**	**8.28%**	**8.75%**	**8.34%**	**7.16%**	**6.13%**	**5.54%**	**5.04%**	**3.85%**	**2.51%**	**1.81%**	**1.54%**

2024 Recorded PLRF Load Percentage Heat Map

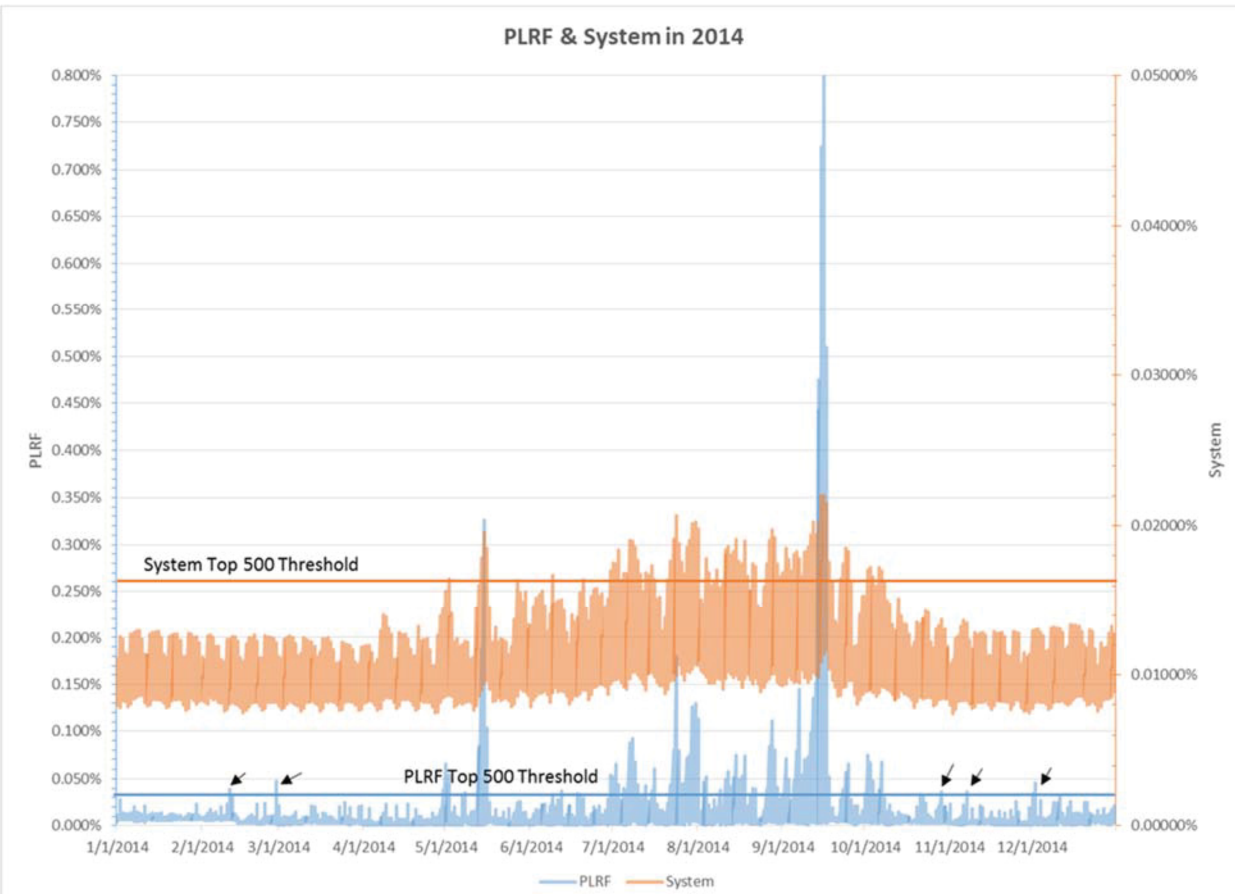
Sum of PLRF — Column Labels

Row Labels	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
WEEKDAYS	**0.98%**	**0.95%**	**0.88%**	**0.87%**	**1.00%**	**1.34%**	**2.07%**	**2.79%**	**3.45%**	**4.21%**	**4.67%**	**5.02%**	**5.75%**	**6.11%**	**6.29%**	**6.06%**	**5.61%**	**5.71%**	**5.58%**	**5.08%**	**3.74%**	**2.25%**	**1.47%**	**1.19%**
JAN	0.09%	0.09%	0.09%	0.08%	0.08%	0.09%	0.12%	0.17%	0.20%	0.21%	0.21%	0.21%	0.20%	0.22%	0.20%	0.18%	0.16%	0.25%	0.26%	0.22%	0.18%	0.14%	0.11%	0.10%
FEB	0.06%	0.06%	0.06%	0.06%	0.06%	0.07%	0.10%	0.14%	0.17%	0.18%	0.19%	0.19%	0.19%	0.19%	0.18%	0.16%	0.12%	0.17%	0.22%	0.19%	0.16%	0.12%	0.08%	0.07%
MAR	0.05%	0.05%	0.05%	0.05%	0.06%	0.09%	0.14%	0.18%	0.19%	0.21%	0.21%	0.22%	0.23%	0.21%	0.18%	0.15%	0.11%	0.13%	0.21%	0.20%	0.16%	0.11%	0.08%	0.07%
APR	0.07%	0.07%	0.06%	0.06%	0.07%	0.09%	0.15%	0.19%	0.22%	0.25%	0.27%	0.28%	0.30%	0.29%	0.29%	0.24%	0.18%	0.16%	0.23%	0.24%	0.18%	0.12%	0.09%	0.08%
MAY	0.07%	0.06%	0.06%	0.06%	0.08%	0.11%	0.21%	0.29%	0.37%	0.47%	0.51%	0.56%	0.65%	0.69%	0.72%	0.71%	0.65%	0.57%	0.50%	0.51%	0.38%	0.22%	0.12%	0.09%
JUN	0.09%	0.09%	0.09%	0.09%	0.10%	0.15%	0.22%	0.27%	0.30%	0.38%	0.40%	0.40%	0.45%	0.46%	0.47%	0.42%	0.37%	0.35%	0.32%	0.35%	0.30%	0.21%	0.16%	0.11%
JUL	0.12%	0.11%	0.10%	0.11%	0.13%	0.18%	0.28%	0.36%	0.46%	0.59%	0.66%	0.75%	0.88%	1.00%	1.09%	1.14%	1.12%	1.08%	0.91%	0.79%	0.62%	0.35%	0.20%	0.15%
AUG	0.11%	0.11%	0.10%	0.10%	0.12%	0.16%	0.25%	0.33%	0.42%	0.53%	0.59%	0.64%	0.76%	0.81%	0.88%	0.87%	0.81%	0.71%	0.62%	0.60%	0.42%	0.23%	0.16%	0.13%
SEP	0.10%	0.09%	0.08%	0.08%	0.10%	0.15%	0.24%	0.36%	0.50%	0.68%	0.82%	0.97%	1.20%	1.34%	1.42%	1.44%	1.38%	1.31%	1.34%	1.18%	0.74%	0.33%	0.16%	0.11%
OCT	0.09%	0.08%	0.07%	0.08%	0.09%	0.14%	0.20%	0.26%	0.30%	0.37%	0.42%	0.44%	0.52%	0.51%	0.49%	0.43%	0.36%	0.43%	0.43%	0.35%	0.23%	0.14%	0.11%	0.10%
NOV	0.07%	0.06%	0.06%	0.06%	0.06%	0.07%	0.09%	0.13%	0.16%	0.18%	0.19%	0.20%	0.21%	0.22%	0.22%	0.19%	0.17%	0.23%	0.22%	0.16%	0.13%	0.11%	0.09%	0.08%
DEC	0.06%	0.06%	0.06%	0.05%	0.05%	0.06%	0.09%	0.12%	0.15%	0.17%	0.18%	0.18%	0.16%	0.17%	0.16%	0.14%	0.18%	0.32%	0.34%	0.30%	0.24%	0.16%	0.10%	0.08%
WEEKENDS	**0.44%**	**0.41%**	**0.37%**	**0.33%**	**0.33%**	**0.34%**	**0.36%**	**0.37%**	**0.40%**	**0.44%**	**0.50%**	**0.57%**	**0.70%**	**0.88%**	**1.07%**	**1.24%**	**1.38%**	**1.50%**	**1.45%**	**1.30%**	**1.00%**	**0.65%**	**0.47%**	**0.41%**
JAN	0.04%	0.04%	0.04%	0.03%	0.03%	0.03%	0.03%	0.03%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.06%	0.06%	0.06%	0.05%	0.05%	0.04%	0.04%
FEB	0.03%	0.03%	0.03%	0.02%	0.02%	0.02%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.04%	0.05%	0.05%	0.04%	0.04%	0.03%	0.03%
MAR	0.03%	0.03%	0.02%	0.02%	0.02%	0.03%	0.03%	0.03%	0.02%	0.02%	0.02%	0.03%	0.02%	0.03%	0.02%	0.02%	0.02%	0.03%	0.05%	0.05%	0.04%	0.03%	0.03%	0.03%
APR	0.03%	0.03%	0.02%	0.02%	0.02%	0.02%	0.03%	0.03%	0.03%	0.03%	0.03%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.04%	0.04%	0.03%	0.03%	0.03%	0.03%
MAY	0.04%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.04%	0.04%	0.04%	0.05%	0.05%	0.06%	0.07%	0.07%	0.07%	0.07%	0.07%	0.09%	0.07%	0.05%	0.04%	0.03%
JUN	0.04%	0.04%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.02%	0.03%	0.03%	0.04%	0.05%	0.05%	0.06%	0.07%	0.08%	0.09%	0.09%	0.10%	0.09%	0.06%	0.04%	0.04%
JUL	0.04%	0.04%	0.04%	0.03%	0.03%	0.04%	0.04%	0.03%	0.03%	0.04%	0.05%	0.07%	0.09%	0.12%	0.15%	0.19%	0.22%	0.23%	0.22%	0.19%	0.15%	0.09%	0.05%	0.04%
AUG	0.05%	0.04%	0.03%	0.03%	0.03%	0.03%	0.03%	0.04%	0.04%	0.04%	0.05%	0.06%	0.09%	0.12%	0.15%	0.19%	0.20%	0.21%	0.18%	0.17%	0.12%	0.08%	0.06%	0.05%
SEP	0.04%	0.04%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.04%	0.07%	0.12%	0.20%	0.28%	0.37%	0.45%	0.52%	0.49%	0.42%	0.34%	0.21%	0.09%	0.05%	0.04%
OCT	0.03%	0.03%	0.03%	0.03%	0.02%	0.02%	0.03%	0.03%	0.03%	0.04%	0.04%	0.03%	0.04%	0.06%	0.08%	0.08%	0.09%	0.11%	0.10%	0.08%	0.06%	0.04%	0.03%	0.03%
NOV	0.05%	0.05%	0.05%	0.04%	0.04%	0.04%	0.04%	0.05%	0.05%	0.06%	0.06%	0.06%	0.05%	0.05%	0.05%	0.05%	0.05%	0.07%	0.07%	0.06%	0.05%	0.04%	0.04%	0.04%
DEC	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.04%	0.07%	0.08%	0.08%	0.07%	0.05%	0.03%	0.03%
Grand Total	**1.42%**	**1.37%**	**1.25%**	**1.21%**	**1.33%**	**1.68%**	**2.43%**	**3.16%**	**3.85%**	**4.64%**	**5.17%**	**5.59%**	**6.45%**	**6.99%**	**7.36%**	**7.30%**	**6.98%**	**7.22%**	**7.03%**	**6.38%**	**4.74%**	**2.91%**	**1.94%**	**1.60%**

The Case for Load Diversity across Circuits

When analyzing the distribution system, it is important to consider the effect of load diversity across the different circuits on the system. Because of the general nature in which the system has evolved over time, in concert with load growth, operational, and safety trends experienced in those timeframes, the distribution system across SCE's service territory will have differences in load profiles, customer composition, and therefore the basic configuration of how the system was built. To capture this effect of diversity across the circuits, the PLRF load variables were first analyzed for each circuit and then aggregated. This two-step process ensures that PLRF load values used in the allocation process account for hourly diversity across circuits prior to aggregating the PLRF load values for the system as a whole. For each hour of the year 2014, Figure 10 illustrates a comparison between SCE's system load value in a given hour expressed as a percentage of the sum of all the hourly system load experienced in the year and the PLRF percentage values described above. The graph has dual y-axes, with the PLRF percentages represented on the left axis and the system load percentages represented on the right axis. The y-axis represents 8,760 hours of the year. A peak threshold line was drawn for the top 500 hours for the system and the top 500 hours for the PLRF values to illustrate that while the method does accommodate the effect of diversity across the circuits, as highlighted by the arrows depicted on the graph, the peak load values experienced on the distribution system are largely consistent with overall system load.

FIGURE 10: 2014 PLRF & SYSTEM



Conclusions

- Marginal costs of the distribution system are a key cost driver used in the revenue allocation process when assigning marginal cost revenue responsibility to rate groups. The use of such costs when determining time of use periods is a natural extension of the role such costs can play in time variant pricing.

- The timing and pattern of distribution peak loads are largely consistent with SCE's overall recorded system peaks. The timing and pattern with which such peaks are experienced may vary by geographical region but is generally consistent across the different regions. As a result, time variant distribution costs can be used to inform time of use periods.
- In a rapidly evolving grid, defining time of use periods requires consideration of a future period. This helps effectively capture the forward looking impact of DERs on the distribution system, specifically the increased penetration of DG. As we have shown, the effect of increased DG penetration tends to shift distribution system peaks to later in the day; similar to the effect that increased Renewable Portfolio Standard (RPS) eligible resources have on overall system load profiles.
- Marginal distribution costs can be split into peak load variant (variable) and non-peak load variant (grid) components using a variety of established methods described above. It is important, however, to adhere to Commission precedence of using long run marginal costs as the basis of such a split.
- The PLRF method is consistent with SCE's planning criteria and can be used to allocate the peak load variant (variable) portion of distribution marginal costs to specific hours of the year. The PLRF allocation captures the diversity in timing of distribution circuit peaks and is an effective means with which to inform time of use periods.

Technology is driving a whole slew of energy platforms that are changing the economic and operating characteristics of the distribution grid. In addition, financial innovation and Commission policies have allowed for higher adoption rates for nascent technologies among consumers. While technology such as solar PV, EV's and intelligent appliances make consumers more conscious about their energy choices, the distribution system evolves into a role that acts as a dynamic medium facilitating the bidirectional flow of power to and from customers. Smart rate design should evolve in concert with this changing landscape in its ability to send effective, sufficient, and cost based price signal to customers. Advances in metering and control technology have laid the foundation of a robust system to manage such power flows should utilities so chose to leverage them. In observance of the important role the distribution grid is expected to play in such a changed environment, it is important that policy guidance also maintain the financial and operational integrity of how the grid accommodates such changes. A critical component will be to utilize time differentiated pricing to allow for a more dynamic and evolved basis of interaction between the utility and the customer. Including distribution as a key cost component of time differentiated pricing is critical in ensuring that distribution rates reflect the time sensitive nature in which the distribution system will be utilized in the future.

Summary of Recommendations

1. Distribution marginal costs can be considered as a key cost component in the analysis supporting time of use periods;
2. Distribution time of use periods reflective of peak capacity needs should be relevant only to the peak load variable component of distribution costs;
3. Distribution costs that are non-peak load variant and reflective of *energy* or base infrastructure needs should be identified and recovered through appropriate pricing mechanisms; and
4. Cost analysis done in support of TOU period definition should be based on a future time period to ensure sufficiency, effectiveness, and stability in the price signal surrounding such period definitions.

Appendix A: Circuit Load and B-Bank Load Factors by Planning Regions

The frequency histograms below illustrate the percentage of circuits and their associated annual load factors by planning regions. In the spread of circuit load factors, San Jacinto has a lower average annual load factor than other regions.

FIGURE 11: DISTRIBUTION OF CIRCUIT LOAD FACTORS BY PLANNING REGION (YEAR 2014)

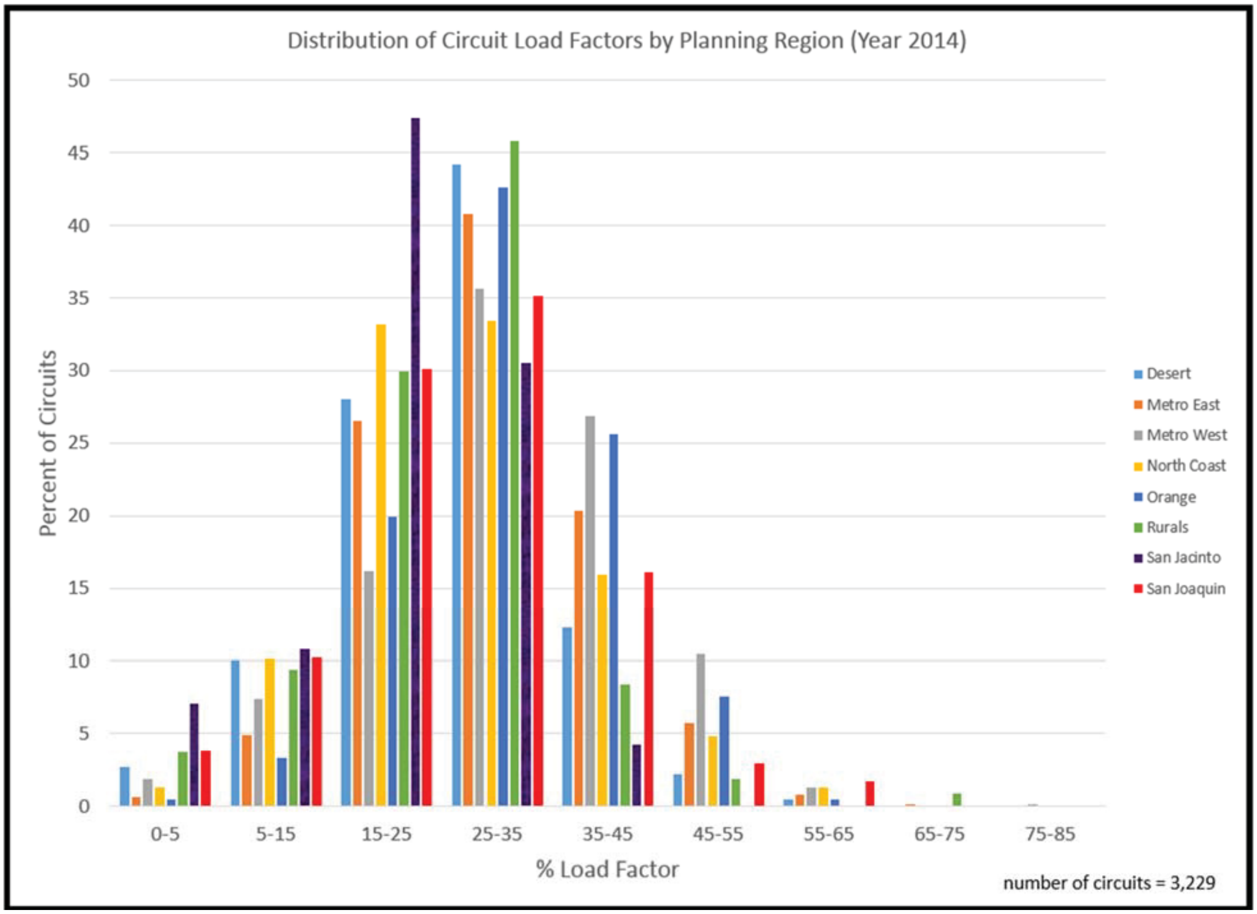


FIGURE 12: CIRCUIT LOAD FACTORS BY PLANNING REGION (YEAR 2014)

	Load Factor (%)								
Region	**0-5**	**5-15**	**15-25**	**25-35**	**35-45**	**45-55**	**55-65**	**65-75**	**75-85**
Desert	2.7	10.1	28.0	44.2	12.3	2.2	0.5	0.0	0.0
Metro East	0.7	4.9	26.6	40.8	20.3	5.7	0.8	0.2	0.0
Metro West	1.9	7.4	16.2	35.7	26.8	10.5	1.3	0.0	0.2
North Coast	1.3	10.1	33.2	33.4	16.0	4.8	1.3	0.0	0.0
Orange	0.5	3.3	19.9	42.6	25.6	7.5	0.5	0.0	0.0
Rurals	3.7	9.4	29.9	45.8	8.4	1.9	0.0	0.9	0.0
San Jacinto	7.0	10.8	47.4	30.5	4.2	0.0	0.0	0.0	0.0
San Joaquin	3.8	10.2	30.1	35.2	16.1	3.0	1.7	0.0	0.0
Frequency Missing = 10									

The frequency histograms below illustrate the percentage of B Banks and their associated annual load factors by planning regions. In the spread of B Bank load factors, Metro East has a lower average annual load factor than other regions.

FIGURE 13: DISTRIBUTION OF B-BANK LOAD FACTORS BY PLANNING REGION (YEAR 2014)

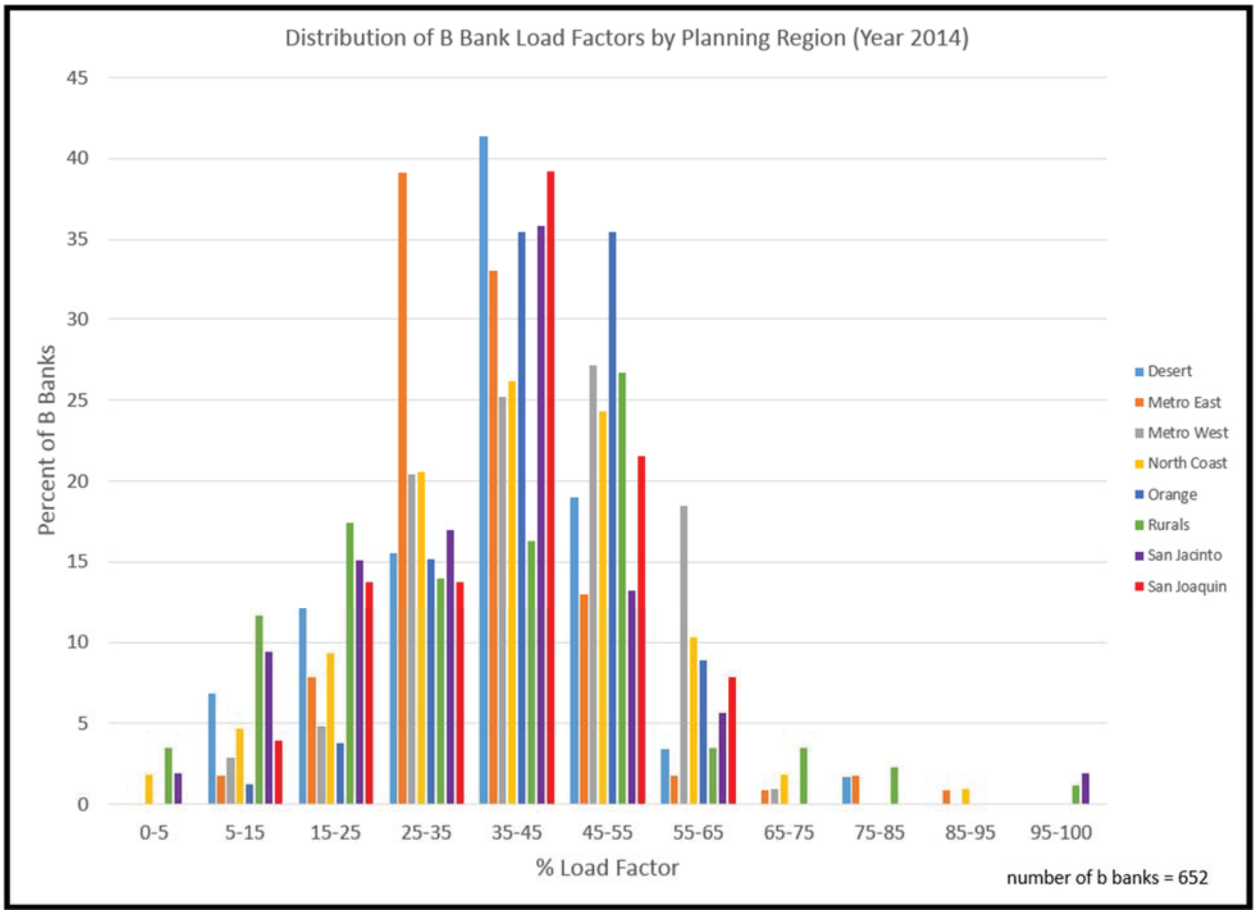


FIGURE 14: B BANK LOAD FACTORS BY PLANNING REGION (YEAR 2014)

	Load Factor (%)										
Region	**0-5**	**5-15**	**15-25**	**25-35**	**35-45**	**45-55**	**55-65**	**65-75**	**75-85**	**85-95**	**95-100**
Desert	0.0	6.9	12.1	15.5	41.4	19.0	3.5	0.0	1.7	0.0	0.0
Metro East	0.0	1.7	7.8	39.1	33.0	13.0	1.7	0.9	1.7	0.9	0.0
Metro West	0.0	2.9	4.9	20.4	25.2	27.2	18.5	1.0	0.0	0.0	0.0
North Coast	1.9	4.7	9.4	20.6	26.2	24.3	10.3	1.9	0.0	0.9	0.0
Orange	0.0	1.3	3.8	15.2	35.4	35.4	8.9	0.0	0.0	0.0	0.0
Rurals	3.5	11.6	17.4	14.0	16.3	26.7	3.5	3.5	2.3	0.0	1.2
San Jacinto	1.9	9.4	15.1	17.0	35.9	13.2	5.7	0.0	0.0	0.0	1.9
San Jacinto	0.0	3.9	13.7	13.7	39.2	21.6	7.8	0.0	0.0	0.0	0.0
Frequency Missing = 11											

The percentages represented in each cells below is the sum of the individual PLRF percentages, by month, and also by planning region. There is a consistent behavior across the different regions, especially in the summer months.

FIGURE 15: PLRF BY MONTH AND PLANNING REGIONS

Row Labels	Sum of DESERT PLRF	Sum of METRO EAST PLRF	Sum of METRO WEST PLRF	Sum of NORTH COAST PLRF	Sum of ORANGE PLRF	Sum of RURALS PLRF	Sum of SAN JACINTO PLRF	Sum of SAN JOAQUIN PLRF	Sum of TOTAL PLRF
WEEKDAYS	**75.5%**	**82.9%**	**80.8%**	**84.2%**	**87.8%**	**68.6%**	**71.9%**	**83.4%**	**81.7%**
JAN	3.6%	3.1%	3.0%	3.5%	2.5%	4.3%	0.2%	1.6%	2.9%
FEB	3.8%	3.1%	2.0%	3.2%	2.8%	4.0%	0.3%	1.8%	2.8%
MAR	3.6%	3.2%	2.0%	3.8%	3.6%	7.7%	0.4%	2.7%	3.4%
APR	3.3%	3.7%	3.6%	4.1%	3.8%	7.7%	0.4%	3.6%	3.9%
MAY	5.8%	8.8%	9.5%	7.3%	12.3%	5.6%	1.0%	5.3%	8.5%
JUN	7.0%	4.8%	4.1%	6.8%	4.5%	6.2%	1.5%	12.5%	5.7%
JUL	16.7%	14.5%	11.2%	13.6%	13.3%	10.3%	19.4%	23.3%	14.5%
AUG	10.5%	12.0%	10.5%	9.2%	11.3%	5.4%	12.2%	16.9%	11.2%
SEP	13.9%	21.4%	17.0%	14.2%	22.8%	4.8%	24.3%	9.6%	17.4%
OCT	2.8%	5.2%	7.4%	8.9%	6.0%	3.3%	5.7%	3.2%	5.5%
NOV	2.0%	1.4%	3.6%	3.8%	2.1%	3.2%	2.5%	1.4%	2.3%
DEC	2.7%	1.7%	6.7%	5.7%	2.9%	6.2%	3.8%	1.6%	3.6%
WEEKENDS	**24.5%**	**17.1%**	**19.2%**	**15.8%**	**12.2%**	**31.4%**	**28.1%**	**16.6%**	**18.3%**
JAN	1.2%	0.3%	1.0%	0.5%	0.3%	1.7%	0.0%	0.1%	0.6%
FEB	1.1%	0.2%	0.6%	0.6%	0.3%	2.1%	0.0%	0.1%	0.5%
MAR	1.1%	0.2%	0.7%	0.5%	0.5%	3.6%	0.3%	0.4%	0.7%
APR	0.9%	0.2%	0.3%	0.4%	0.2%	2.8%	0.1%	0.5%	0.5%
MAY	1.7%	0.7%	0.9%	0.5%	0.8%	3.0%	0.1%	1.2%	1.0%
JUN	2.0%	0.5%	0.8%	0.8%	0.2%	2.8%	0.5%	2.6%	1.0%
JUL	4.1%	2.9%	2.3%	2.4%	1.3%	4.1%	4.2%	6.1%	2.9%
AUG	3.7%	2.9%	2.8%	2.1%	1.5%	2.7%	4.9%	3.6%	2.7%
SEP	6.1%	7.8%	4.8%	3.7%	5.6%	2.2%	13.5%	1.7%	5.5%
OCT	1.2%	1.0%	1.8%	1.7%	0.7%	1.1%	2.0%	0.1%	1.1%
NOV	0.9%	0.2%	1.2%	1.2%	0.4%	2.2%	1.0%	0.2%	0.7%
DEC	0.6%	0.4%	2.2%	1.4%	0.5%	3.0%	1.6%	0.0%	1.0%

Appendix B: Distribution System Planning Criteria

1. Planned Loading Limit (PLL): This is the normal operating capacity of a distribution system asset and is based on the following:
    a. Circuits
        i. OH conductor and UG cable should be limited to 100 percent of the thermal rating as defined in SCE's Design Standard
        ii. 75 percent of the rating of the main upstream protective device
        iii. The normal rating of the limiting component on the system
        iv. Reserve capacity so as not to exceed emergency ratings which for UG cable is typically temperature dependent
        v. Planning review flag set at 73 percent of the average PLL of the circuits at a given substation
    b. Distribution Substations
        i. Nameplate rating of substation capacity is the threshold for which a capacity analysis trigger is initiated
        ii. Substation PLL is typically 130 percent of the Nameplate rating for normal loading and 145 percent of nameplate for Emergency Loading Limits (ELL)
        iii. ELL should not be exceeded for a substation when planning for a N-1 contingency
        iv. Capacity addition at an existing substation is typically a 28 MVA transformer
        v. A new substation should be designed to accommodate up to four 28 MVA nameplate capacity rates transformers and associated equipment
        vi. Planning review flag set at 90 percent of the substation PLL after accounting for temperature sensitivities

2. Criteria Projected Load: A forecasted peak load that is temperature adjusted to the current approved heat storm criteria. This forms the starting point when analyzing load growth forecasts on the distribution system and the projections of such load triggers the need for capacity planning.

3. Criteria Reserve: A measure of the difference between Criteria Projected Load and the PLL. This measure indicates the amount of reserve available before a capacity planning decision will need to be made.

ENDNOTES

[1] Under PG&E's PCAF methodology, the peak usage day for each region is used to establish a minimum threshold value base on a selected percentage of the total. Once established, all hours of usage that exceed that threshold throughout the year are considered for evaluation. Each of the qualifying hours are then divided into the individual rate schedule's contribution to the total. These percentages are then averaged over all of the hours to determine a weighted percentage by rate schedule for the year. Both SCE and PG&E use measures of distribution coincidence (i.e. a TOU element) to assign distribution functional costs to rate groups. A key issue is the ability afforded to carry-through these TOU-based cost elements to the individual customer level through specific TOU rate elements.

[2] Southern California Edison, "Application 14-06-014: Phase 2 of 2015 General Rate Case Marginal Costs and Sales Forecast Proposals," Exhibit SCE-02, section I.C.1.b (2).2, pp.32-34, Jun. 2014.

[3] J. C. Bonbright, A. L. Danielsen, and D. R. Kamerschen, Principles of Public Utility Rates. Public Utilities Reports, Incorporated, pp. 377-407, 1988.

[4] S. Voll and H. Parmesano, "Rethinking Rate Design for Electricity Distribution Service," National Economic Research Associates, 2005.

[5] J. J. Doran, "Electric Utility Cost Allocation Manual," National Association of Regulatory Utility Commissioners, 1973.

[6] The color scale for all heat map plots contained in this paper use the following conditional formatting rule: top 10th percentile values shown in red; midpoint values (50th percentile) in yellow; and bottom 10th percentile values shown in green.

[7] The physical scheduling for new circuit capacity in the planning horizon is initiated only when the criteria projected load reaches 100 percent of PLL.

[8] Note that when normalizing these values using PLLs for each circuit, the lower overall values in the 2024 tables provide some insights into the overall (average) penetration of DG on the distribution system. This value varies for each hour and each circuit.