BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) for Approval of its 2016 Rate Design Window Proposals.	Application 16-09-003 (Filed September 1, 2016)

OPENING BRIEF
OF THE OFFICE OF RATEPAYER ADVOCATES
ON SOUTHERN CALIFORNIA EDISON'S
2016 RATE DESIGN WINDOW APPLICATION

SELINA SHEK
Staff Counsel for

Office of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Telephone: (415) 703-2423
Email: selina.shek@cpuc.ca.gov

ERIC DURAN
Regulatory Analyst for

Office of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Telephone: (415) 703-2002
Email: eric.duran@cpuc.ca.gov

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I. INTRODUCTION

Pursuant to Rule 13.11 of the California Public Utilities Commission's Rules of Practice and Procedure, the Office of Ratepayer Advocates ("ORA"), hereby submits its Opening Brief in Southern California Edison Company's ("SCE" or "Edison") Application ("A".) 16-09-003 for approval of its 2016 Rate Design Window ("RDW") Proposals. Edison filed its Application on September 1, 2016, and ORA filed its Protest on October 7, 2016. ORA submitted its testimony on April 28, 2017 and Edison served its Rebuttal on June 9, 2017. The Commission held evidentiary hearings on August 7 and 9, 2017.

ORA's brief follows the Common Briefing Outline Edison circulated on August 21, 2017 to the Service List. This brief primarily addresses issues regarding time-of-use ("TOU") periods including marginal costs and final TOU period proposals. Subsequent sections discuss critical peak pricing ("CPP"), real time pricing ("RTP"), marketing, education and outreach ("ME&O"), the distributed energy resources ("DER") action plan, and the Option R cap. ORA's brief covers selected subjects and a lack of a response on any issues should not be construed as ORA's agreement on those issues.

II. TIME-OF-USE CONSIDERATIONS

a. Marginal Costs

i. Reference Year

Using 2021 Marginal Cost Data Complies with the Commission's TOU Period Design Guidelines and Reduces Forecasting Error

The Commission should use marginal cost forecasts for year 2021 to determine TOU periods. In 2017, the Commission determined that "Base TOU periods should be developed using forward-looking data, with the forecast year set at least three years after the year the Base TOU period will go into effect,"[1] and that these Base TOU periods "should continue for a minimum of five years…"[2] SCE intends to implement its new

[1] TOU Order Instituting Rulemaking ("OIR") Decision (D.) 17-01-006, pp.7.

[2] *Ibid.*

TOU periods (Base TOU periods) in February 2019.[3] Year 2021 falls within the mid-range of the five years for retaining the Base TOU periods. In contrast, SCE proposes using a forecast of 2024 marginal cost, five years past the implementation date, and nearly eight years after the forecasts were made. Developing TOU periods on a projection so far out into the future introduces substantial uncertainty and increases the likelihood of forecasting errors. Mr. Garwacki, SCE's witness, acknowledged this, when he concurred with Counsel for the Solar Energy Industries Association ("SEIA") that uncertainty increases as forecasts are made further out into the future.[4] ORA's recommendation to base TOU periods on 2021 marginal costs is more realistic, will reduce forecast uncertainty, and complies with the directives in the TOU OIR.

SCE argues that it is appropriate to use 2024 forecasts because SCE thinks there may be changes to the Renewable Portfolio Standard ("RPS") mandates that would impact future marginal costs.[5] SCE witness Garwacki cited legislation under consideration such as Senate Bill ("SB") 100, which has been revised significantly since its introduction.[6] SCE's attempt to consider pending legislation in this proceeding is unnecessary as the Commission has already established a mechanism for modifying TOU periods in instances where there are significant changes to material facts or assumptions. In the TOU OIR Decision, the Commission states:

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[3] SCE Rebuttal Testimony, Exh. SCE-03,pp.71.

[4] Q: "[a]ren't forecasts more uncertain the further out into the future one goes?" A: "Yes." Reporters Transcript (RT), , Volume #1, p. 104 line 9**.**

[5] RT, Volume #1, p. 85 line 14**.**

[6] *See* https://leginfo.legislature.ca.gov/faces/billVersionsCompareClient.xhtml?bill_id=201720180SB100, accessed 9/5/17. To date, this bill has been amended five times since its introduction on 1/11/17. Amendments include changes to the RPS percentages proposed and target years.

> Base TOU periods should continue for a minimum of five years (***unless material changes in relevant assumptions indicate the need for more frequent Base TOU period revisions***) and each IOU should propose new Base TOU periods, if warranted, at least every two general rate case cycles (emphasis added).[7]

In the event passed legislation has *material* impacts on the determination of TOU periods, SCE can revise Base TOU periods as set forth in the Commissions' guidelines.

ii. Generation

The Commission Should Adopt ORA's Allocation of Marginal Generation Capacity Costs During Ramping Hours Because it Appropriately Reflects Cost Incidence

The Commission should approve ORA's method for allocating marginal generation capacity costs ("MGCC") because it is consistent with the Commission's order that TOU periods be based on marginal costs.[8] Conversely, the Commission should reject SCE's method of MGCC allocation as it is arbitrary and based on false assumptions. Specifically, SCE proposes splitting the allocation of MGCC costs into meeting system peak capacity and flexible ramping capacity need. SCE proposes allocating 40% of the MGCC value to the daily ramping hours and 60% to system peak capacity using a Loss of Load Expectation ("LOLE") approach. SCE defines the daily ramping hours as the "greatest upward three-hour net-load" period where demand increases most.[9] Within the three daily ramping hours, SCE proposes allocating 30%[10] of the flexible ramping capacity costs to hour 2 and 70% to hour 3.[11]

ORA does not object to the proposal to split peak related and flexible ramping related capacity costs. Further, ORA does not dispute SCE's definition of the daily

[7] TOU OIR D.17-01-006, pp. 7.

[8] *Ibid.*

[9] SCE Opening Testimony, Exh. SCE-1, pp.27.

[10] Of the aforementioned 40% of the MGCC value related to flexible ramping capacity.

[11] These proposals are discussed in SCE's Opening Testimony, Exh. SCE-1, Chapter III, Sections 2.b – 2.d.

ramping hours. However, ORA does contest SCE's flexible ramping capacity cost allocation method (70/30% in ramping hours 3 and 2, respectively).

SCE's method of allocating the flexible ramping capacity related costs runs contrary to the Commission's TOU OIR guidelines that base TOU periods on marginal costs. Appropriate TOU periods should reflect how marginal costs change throughout the day and should not be fixed at specific values. SCE's method of assigning a *fixed* allocation of MGCC costs to ramp hours 2 and 3 ignores that ramping needs change throughout the day and that the first hour in a ramp can have significant costs.

In addition to being consistent with the Commission's TOU OIR guidelines, ORA's proposed method provides a straightforward approach. Rather than assigning fixed hourly ramp allocations of MGCC,[12] ORA relies on net load data to determine each hour's relative weight on the total three hour ramp. The following table shows this process using net load data for the maximum daily ramp on November 1, 2021.

Date	Hour	Hour Ramps (MW)	RAMP HOUR	ORA RAMP ALLOCATIONS (% of ramp)	SCE RAMP ALLOCATIONS (fixed %)
11/1/2021	15	1,594	1	16%	0%
11/1/2021	16	3,302	2	32%	30%
11/1/2021	17	5,303	3	52%	70%
Sum of all Ramp Hours		**10,199**			

The result is that the first hour of the ramp is weighted at 16% of the total flexible ramping capacity costs assigned to this day. SCE's method would not assign any weight to this hour and instead would overvalue costs in the third hour of the ramp. ORA's method properly assigns weights to daily ramping allocation based on the net load data for that day. This is important as ramping needs can vary across all ramping hours and throughout the year.[13] Also, ORA's method does not make the assumption that hour 3 has the steepest ramp, and instead allows the data to dictate how each hour should be

[12] SCE's fixed allocations are 0% in hour 1, 30% in hour 2, and 70% in hour 3.

[13] SCE's Figure IV-35 in its Opening Testimony, Exh. SCE-1, shows that some months have a steeper ramp than others.

weighted. And again, ORA's method is consistent with the essence of the TOU OIR, which sought data-driven approaches for determining TOU periods.[14]

SCE's main argument for its 70/30 split method is that it provides a more effective price signal to customers.[15] However, the aggregation of marginal costs into TOU periods dilutes any price signal associated with a single marginal cost component and therefore renders this argument moot. In theory, the notion that SCE's allocation will send a price signal can only be based on the assumption that customers will pay rates that are differentiated from one hour to the next. SCE's proposal to send price signals through a single marginal cost component is flawed and based on unrealistic assumptions. In any case, the allocation of flexible ramping capacity costs should be based on data.

The Commission should reject SCE's method because it is arbitrary and based on assumptions that do not reflect recorded data. ORA's data-driven proposal to base the allocation of ramping costs with actual ramping data across all ramping hours is more appropriate and should be adopted.

iii. Distribution

The Commission Should Examine SCE's Distribution Marginal Cost Allocation in Future Rate Design Proceedings

SCE's allocation of distribution marginal costs in this proceeding is acceptable.

iv. Transmission

The Commission Should Continue to Analyze Transmission Costs in Future Proceedings

ORA does not take a position on the magnitude of marginal transmission costs. We fully support the Commission's finding in D.17-01-006 that says "… while we do not

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[14] See discussion 2.1 "Data Requirements Underlying Base TOU Periods" of TOU OIR D.17-01-006, pp. 13 – 15.

[15] SCE Opening Testimony, Exh. SCE-1, pp. 30, lines 1 – 3.

regulate FERC-regulated transmission rates, we find it appropriate to recognize the time profile impact of system loads that drive transmission costs in the design of TOU time periods."[16] But, as that decision also notes, "The use of distribution and transmission marginal cost data in determining Base TOU periods will not be simple." [17]

Although ORA does not take a position on the magnitude of marginal transmission costs, the allocation of those costs will have a non-trivial impact on the designation of TOU periods. Further investigation should occur in future proceedings. Until that work can be done, the Commission should not make a radical change in the TOU periods that may have to be "walked back" when the TOU periods are altered again. Accordingly, a more moderate move to a summer peak to 3 pm to 8 pm, in contrast with SCE's more aggressive move to 4 pm to 9 pm, would be the most appropriate.

The two graphs on the next page demonstrate that the allocation of transmission costs has a non-trivial impact on TOU period determination. The first shows SEIA's allocation of transmission costs[18] and the second shows SCE's recommended allocation.[19] As shown, the transmission costs in SEIA's analysis are allocated mainly to hours 15 - 20, whereas they are allocated to hours 17 - 23 in SCE's analysis.

These differences stem from the use of different allocation methods. SEIA "calculated a set of peak cost allocation factors ("PCAFs") based on those hours with loads within 10% of the annual maximum hourly SCE load on the CAISO system, using SCE's forecast of delivered load in 2021."[20] In contrast, SCE starts with what essentially is a 12-CP method[21] and then allocates the monthly results equally to the top 20 peak load hours of each month. As SCE explains:

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[16] TOU OIR D.17-01-006, p. 30.

[17] *Ibid*, p. 31.

[18] SEIA Opening Testimony, Exh. SEIA-01, Executive Summary, p. ii.

[19] SCE's Rebuttal Testimony, Exh. SCE-03, p. 24.

[20] SEIA Opening Testimony, Exh. SEIA-01, p. 16.

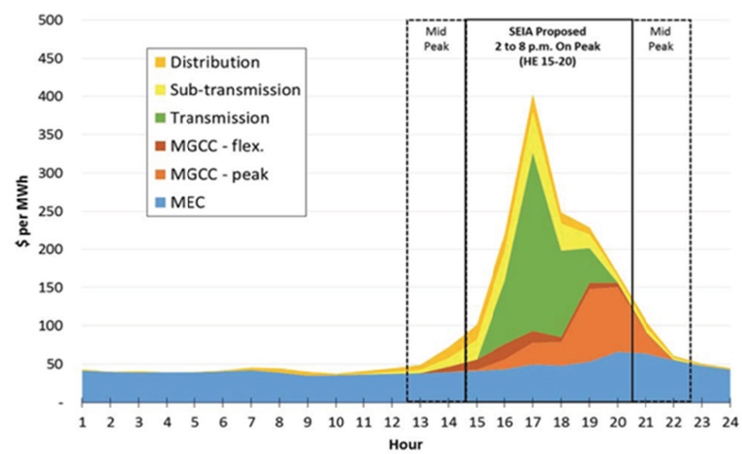
[21] This refers to FERC's method of allocating costs to the coincident peaks (CP) occurring in each of the 12 months of the year.

> The capacity-related portion of transmission system marginal costs were allocated to each month based on the relative proportion of monthly peak load estimated for the year 2024. To arrive at an hourly allocation of costs, this monthly allocation was then equally prorated to the top-20 peak load hours of each month. (SCE Rebuttal, p. 20)

The PCAF (SEIA) and 12-CP (SCE) methods result in very different allocations. The record in this proceeding is insufficient to allow full evaluation of the two methods and determine which one is more appropriate. Accordingly, this issue should be further considered in future GRCs.

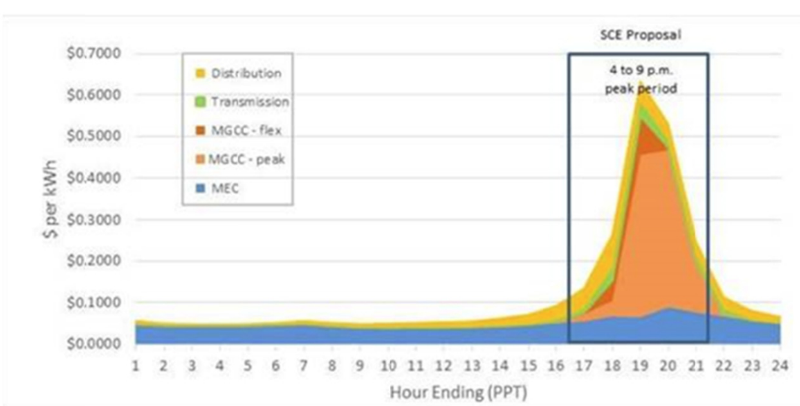
Analysis of SEIA

Figure ES-1: Summer 2021 (May - October) Marginal Costs



Analysis of SCE

Figure III-9
2024 Average Total Marginal Cost including Transmission ($/kWh-hr) – Summer Weekday



b. Periods

ORA's On-Peak Period of 3 P.M. to 8 P.M. Reflects the TOU OIR's Policy Objectives

ORA's marginal cost data supports the on-peak period of 3 P.M. to 8 P.M. Further, the 3 P.M. to 8 P.M. on-peak period is a more gradual change from the current on-peak period of 12-6 P.M.[22] than SCE's proposal of 4 P.M. to 9 P.M. ORA's proposal appropriately reflects the TOU OIR's policy objectives in that it is based on SCE-specific marginal costs and it takes into account customer considerations more so than SCE's proposal.

ORA's peak period proposal is a more gradual change for customers who have faced the same TOU periods for more than 30 years. As SCE's witness Dr. Kan testified, SCE's on-peak proposal is a "very drastic change" and that "customer acceptance should be considered."[23] SCE provides a similar conclusion in their response to an ORA data request, stating that "there are several [TOU] scenarios that yield quite comparable results and therefore, customer considerations may rightfully be a deciding factor."[24]

c. Day Type Differentiation (Weekday / Weekend)

Not Contested.

d. Seasonal Definitions

Not Contested.

e. TOU Period Grandfathering

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[22] SCE's current non-residential on-peak period is from noon to 6 P.M.

[23] In hearings, Dr. Kan stated that "Our customers have been used to the same seasons for 30 years. And so if we are going to change the hours -- the on-peak hours, ***which is a very drastic change*** maybe, then we -- SCE deemed that it would be reasonable based on the data that I just presented and also on ***the customers' acceptance*** that it would be preferable to keep the same seasons, June through September" (emphasis added). RT, Volume 1, p. 49 line 18.

[24] Attachment E of ORA's testimony, Exh. ORA-1, is SCE's data response to ORA's fifth Data Request. In the response, SCE describes their regression process for measuring the effectiveness of various TOU periods.

Not Contested.

f. Other Mitigation Measures

Not Contested.

g. Implementation

SCE's Implementation Plan From its Rebuttal Testimony is Acceptable

In Opening Testimony, ORA recommended SCE's proposed two-pronged implementation plan. SCE, in response to other intervenors' concerns, proposed to consolidate its RDW implementation plan with its 2018 General Rate Case ("GRC") Phase 2 application.[25] ORA supports SCE's revised implementation plan, and with an emphasis on communication and outreach on the lowest-usage small commercial ratepayers.[26]

III. CRITICAL PEAK PRICING ("CPP")

The Commission Should Adopt SCE's Optional CPP for Small Commercial Customers

The Commission should approve SCE's alternative proposal, which would make CPP rates optional for small commercial customers (those with less than 20kW of demand per month). SCE provides sufficient evidence to indicate that load shifting from small commercial customers, as a result of CPP, will be to be negligible.[27] Further, no other intervening party opposed this alternative proposal.

IV. REAL TIME PRICING

Not Contested

[25] SCE's Rebuttal Testimony, Exh. SCE-03, p. 71.

[26] ORA Opening Testimony, Exh. ORA-1, pp. 17, line 20.

[27] SCE's estimated load reduction is based on the results of PG&E's default CPP pilot. SCE estimates its small commercial customers would reduce load by 1.3 MW or 4.5% of its estimated total CPP load. This also amounts to 0.09% of SCE's total demand response portfolio. See SCE Opening Testimony, page 105, for more details.

V. MARKETING, EDUCATION, AND OUTREACH

SCE's ME&O Should Focus on Informing the Customers Most Impacted by These TOU Periods

SCE's Marketing, Education, and Outreach ("ME&O") campaign should focus on small commercial customers, especially those with the lowest average usage. ORA demonstrated that the lowest-usage customers in the TOU-GS-1 rate group will bear the biggest rate impact, while customers with the highest usage in that group will be net benefiters.[28] SCE should focus its ME&O campaign on informing these low-usage customers of the options available to mitigate the impact from TOU period changes with balanced payment plans. Although SCE currently offers balanced payment plans to small commercial customers, it should raise awareness of this offering to help customers who encounter volatile bill impacts and therefore reduce their bill/rate shock.

VI. DISTRIBUTED ENERGY RESOURCES ACTION PLAN

Not Contested.

VII. OPTION R CAP

Not Contested.

VIII. CONCLUSION

The Commission should adopt ORA's recommendations in A.16-09-003.

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[28] ORA Opening Testimony, Exh. ORA-1, pp. 12 – 16.

Respectfully submitted,

/s/ SELINA SHEK

Selina Shek
Attorney for

Office of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Telephone: (415) 703-2423
Fax: (415) 703-2262
E-mail: selina.shek@cpuc.ca.gov

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