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.	Rulemaking 15-12-012 (Filed December 17, 2015)

OPENING COMMENTS OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION RESPONDING TO SCOPING QUESTIONS

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In accordance with the *Scoping Memo and Ruling of the Assigned Commissioner and the Assigned Administrative Law Judge* issued in the above captioned proceeding on May 3, 2016 (Scoping Memo), the Solar Energy Industries Association (SEIA)[1] submits its responses to the Scoping Questions. SEIA has participated actively in this proceeding, including the prior comments as well as the multiple workshops that the Commission's Energy Division has hosted. SEIA supports the Commission's goal of bringing greater definition and consistency to the methodology used to set time-of-use (TOU) periods. This goal is particularly important given the increasing use of time-varying rates in the rate designs for all classes of utility customers.

I. INTRODUCTION

California is pursuing a number of strategies for increasing the penetration of renewable energy in the state and, specifically, for managing concerns about seasonal periods of overgeneration and steep evening ramps that result from a net load[2] curve known as the "duck curve." These strategies include demand flexibility measures, such as demand response

[1] The comments contained in this filing represent the position of the SEIA as an organization, but not necessarily the views of any particular member with respect to any issue.

[2] "Net load" is defined as the system load curve net of non-dispatchable intermittent renewable energy generation.

programs and TOU rates. They also include market changes such as greater regional integration of wholesale electricity markets and resource changes to the fleet of thermal generators. In this context, TOU rates as a renewable energy integration strategy must be viewed holistically -- both in terms of their potential contribution to responding to the duck curve, but also in terms of how a change in TOU periods may impact customers. SEIA also cautions the Commission that today's customers are making long-term investment decisions in reliance on the price signals conveyed by today's TOU periods. As a result, in order to respect these investments, TOU periods should evolve in a measured way, based on the time profile of all utility marginal costs, on reasonable evidence that these marginal cost profiles are changing, and with adequate time for customers to understand and adjust to these changes.

In order to take advantage of periods of time when renewable power is most abundant, customers must be able to consume this power to some useful end. In theory, TOU periods would closely follow system conditions at the wholesale level, and TOU rates would provide customers with an opportunity to shift their consumption from times of the day that are more operationally challenging to times of abundant clean energy, and in particular to times when there is a risk of overgeneration. In practice, customers' ability to respond varies based on their energy usage, on their awareness and understanding of the time profile of this usage, and on their access to enabling technologies to shift or modify their energy consumption. Moreover, the ability to react is complicated by the fact that many of the most challenging system conditions related to the duck curve will occur in the shoulder seasons, when loads are light, and many customers will not be well situated to respond.

In addition, any efforts to transition customers to new TOU periods and rate designs must recognize the length of time needed for these transitions to yield changes in behavior. This challenge was recognized in the recent decision (D.15-07-001) on residential rate reform. Future changes to TOU periods resulting from the instant proceeding and concurrent general rate cases will be implemented as the electricity system in California undergoes important changes. With significant changes to the wholesale energy system anticipated within the decade, including a potentially major change to the footprint of the California Independent System Operator (CAISO), TOU rates and the principles underpinning them must be able to adapt to changes in wholesale system needs while providing certainty for customers so that they can make investments in response to the current TOU rates and periods.

While the state seeks TOU rates as a response to wholesale system needs – particularly the integration of renewable energy – its TOU rate designs should recognize that retail electric rates recover costs for all components of electricity service: generation, transmission, and distribution. Retail rates also send important price signals to customers related to their use of the electric delivery system, as well as their consumption of electric energy and generation capacity. The time-varying demand of customers on the transmission and distribution systems drives the need for capacity on the delivery system in the same way that peak demands cause generation capacity costs to be incurred. As demonstrated below, SEIA's review of substation data from Southern California Edison shows that distribution peaks are typically earlier than the system peak. This difference in distribution peaks, and their associated costs, should be incorporated into the determination of the appropriate TOU periods.

Further, as the CAISO acknowledged at the initial workshop in this proceeding, periods of steep up-ramps present challenging conditions for system operators. At these times, operators must rely on the more limited set of resources that is capable of being dispatched upwards. These periods result in additional costs for flexible capacity, although the exact quantification of these costs remains a work in progress. Nonetheless, these added costs mean that the on-peak TOU period should include the challenging period of the maximum up-ramp prior to the net load peak.

It is in this context of customers' varying ability to respond to TOU rates, changing system needs, and the marginal costs recovered by rates that SEIA responds to the questions from Scoping Memo. Our responses to the questions below include SEIA's recommendations for how the time profile of marginal costs should inform the choice of TOU periods to be used in the rate designs we proposed in our April 6, 2016 filing. In that filing, SEIA recommended the creation of default TOU rates that are simple to understand and have moderate differentials between on- and off-peak rates (referred to as "TOU-lite"). We also recommended that a suite of optional rates could yield meaningful customer response to system needs, both in response to the duck curve but also to more local needs, particularly local distribution system peaks.

Recent findings by the Public Utilities Commission, the Energy Commission, and the Independent System Operator (hereafter referred to as the *"Joint Agency TOU Load Shifting Analysis"*) support SEIA's approach, as they show that most customers are unlikely to shift large amounts of load to periods of overgeneration. Even among large commercial and industrial (C&I) customers, where it is estimated that between 3.0% and 3.7% of load could be shifted from evening to early afternoon periods, there is considerable uncertainty in the likelihood of such beneficial shifts.[3] These findings suggest more research and piloting is needed; optional rates can provide further insight into how customers will respond.

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[3] Simon Baker, Silvia Bender, and Thomas Doughty, *Joint Agency Staff Paper on Time-of-Use Load Impacts*, December 2015, hereafter "Baker et al." Filed as supplemental analysis in the California Energy Commission's *2015 Integrated Energy Policy Report* proceeding.

II. GENERAL GUIDELINES FOR TOU PERIODS

At the conclusion of the June 8, 2016 workshop in this proceeding, ALJ McKinney indicated that the likely outcome of this rulemaking will be a set of general guidelines to bring greater definition and consistency to the data and methodology used to determine TOU periods in the rate design Phase 2 portions of utility general rate cases. The ALJ indicated that the detailed responses to the questions in the Scoping Memo will be used to inform the development of these guidelines. Accordingly, SEIA summarizes below its recommended guidelines for Commission adoption in this rulemaking. SEIA believes that these guidelines are well-supported in its responses below to the questions in the Scoping Memo, as well as by its prior comments.

<u>SEIA's Guidelines for Choosing TOU Periods</u>

1. **Based on marginal costs.** TOU periods should be based on the time profile of the utility's marginal costs,

2. **Use all marginal cost elements that vary with usage and demand.** All elements of a utility's marginal cost of service that vary with customers' usage and demand for electricity – generation, transmission, and distribution – should be considered in setting TOU periods. The Commission should treat all utility costs except for customer-related costs as "variable" or "time-dependent" for the purpose of determining TOU periods.

3. **Address operational challenges.** The TOU periods selected should address those times of challenging system operating conditions, such as hours of potential overgeneration or steep net load up-ramps.
   a. On-peak TOU periods should focus on the hours prior to the net load peak that have the steepest up-ramps in net loads and thus require the greatest additions of unloaded, dispatchable generation.
   b. The hours after the net load peak are not as critical, as there will be more means available to reduce generation to meet down ramps.

4. **Data.** The data used to determine TOU periods should include the following load data:
   a. Customer load for end-use consumption (L1)
   b. Metered customer load net of load served with behind-the-meter generation (L2)
   c. Loads at distribution substations (L3)

d. Loads at the system level net of intermittent renewable or must-take generation (L4 - net load or L5 - adjusted net load)
e. System loads served from the transmission system, without adjustment (which SEIA has labeled as L6).

5. **Forecasts.** Forecast data used to choose TOU periods should be based on transparent sources and should be consistent with data used in the Commission's other long-term procurement and planning dockets. Forecasts of system conditions in the future should focus on conditions expected at the mid-point of the period for which the new TOU periods are expected to apply.

6. **Simplicity.** TOU periods for rates designed to be the default or to be broadly available should be simpler in structure; more complex sets of TOU periods can be used in optional rates designed to target particular system conditions.

7. **Five years duration.** Consistent with Public Utilities (P.U.) Code Section 745(c)(3) and the policy that the Commission expressed in R. 12-06-013, TOU periods should be set for periods of at least five years.

8. **Wholesale TOD based on location.** The choice of time-of-delivery (TOD) periods for wholesale generation should consider the wholesale generator's location on the grid, and may differ from retail TOU periods on that basis.

9. **Change TOU periods in GRC Phase 2 cases.** Changes to TOU rates should occur as part of General Rate Case (GRC) Phase 2 proceedings.

10. **Grandfathering.** Implementation of changes to TOU periods should allow for grandfathering of customers on rate schedules with existing TOU periods so as to provide certainty around investments in distributed energy resources. A grandfathering period of ten years plus a subsequent transition period is recommended for the TOU periods for existing solar customers on today's TOU rates. In the future, TOU periods should be set for a minimum of five years.

III. RESPONSE TO QUESTIONS

The Scoping Memo, at page 8, clarifies that the purpose of this proceeding is to address the following issues concerning the design and selection of TOU periods:

- In the near-term, what are the minimum requirements for data, analysis and information to support a request to change TOU time periods?

- What methodology should be used to incorporate minimum data requirements into analysis of proposed changes in TOU time periods?

- What other steps, if any, should be taken when evaluating proposed TOU rate changes to ensure rates appropriately address grid needs, cost causation, customer acceptance and other legal requirements of rate design?

As a framework for addressing these issues, the Scoping Memo asks parties to respond to a set of questions in two groups. Group A consists of questions about the data and methodology that the Commission should require the utilities and parties to use in rate proceedings where TOU periods may be at issue. The Group B questions focus on customer acceptance of the chosen TOU periods. SEIA presents below its responses to both sets of questions.

A. Methodology for Setting TOU Periods

1. ***Which data are relevant to setting TOU periods from a grid perspective? What existing studies and data sources provide data you recommend? If you recommend that load profile data should play a role in setting TOU periods, specify the type of load you propose using, referring to Table 1 above, and explain why that approach to measuring is preferable. If the data is not currently available, would you propose developing this data for setting future TOU periods? If so, what steps would you recommend taking to develop the data?***

- ***Hourly metered load, net load, and usage data, disaggregated by location, customer class.***
- ***Hourly wholesale supply data, disaggregated by location and type of generation.***

Response: TOU periods should be set considering how time-varying loads impact the causation of all types of utility costs – generation, transmission, and distribution – on all portions of the utility system upstream of a customer's specific meter and service drop. As a result, all of the load data listed in Table 1 of the Scoping Memo is potentially relevant to the determination of appropriate TOU periods. Accordingly, a utility proposing a set of TOU periods should provide the load data in Table 1 for at least the most recent three-year period, as well as on a forecast basis if the TOU period proposal is based on a forecast. The only load data that may be difficult to obtain are the end-use consumption data (L1), because there can be limited visibility into the exact profile of end-use loads that are also served by behind-the-meter generation or storage. Metered load data (L2) is probably adequate as a proxy for L1 until there is greater visibility into the behind-the-meter use of distributed energy technologies, such that the L1 consumption data can be measured accurately.

IOUs clearly have historical metered load data (L2); this data shows the time-varying demand placed on the distribution system closest to the customer. The utilities also have historical load data at their distribution substations (L3), which shows loads on the higher-voltage distribution and sub-transmission systems. SEIA recently obtained such data for 2015 from SCE for its more than 500 A-bank and B-bank distribution substations. Obviously, this data is location-specific, but it does not have to be used to set geographically disaggregated rates. Instead, the load profiles on the distribution and sub-transmission systems should be made available and analyzed to determine the overall hourly load patterns that drive distribution and sub-transmission marginal costs, for comparison to the load profiles at the system level that cause generation and transmission marginal costs to be incurred.

SEIA recognizes that “net” load data, either metered loads net of contracted wholesale wind and solar (L4) or metered loads net of contracted “must take” resources (so-called “adjusted net loads,” L5) will have relevance for identifying periods of challenging system conditions, such as steep late afternoon up-ramps or midday periods of potential overgeneration. These types of net load data should be available by utility service territory, based on CAISO wholesale supply data available to the utilities.

Finally, the Commission also should consider system loads served from the high-voltage, bulk transmission system, without adjustment for specific types of generation. These loads (perhaps designated L6) are relevant to cost causation on the high-voltage CAISO-controlled transmission system, which must deliver the bulk of the utilities' wholesale purchases and generation to the lower voltage subtransmission and distribution systems. This load data is readily available to any party through the CAISO's OASIS site.

- ***Estimated hourly load and supply for years through 2020.***

Response: Data on estimated hourly loads and supplies into the future can inform the choice of TOU periods. These forecasts should be based on transparent methodologies and should be consistent with both (1) the California Energy Commission load forecasts used in Long-term Procurement Planning (LTPP) cases and (2) the supply assumptions used for LTPP modeling and for CPUC-approved tools such as the RPS Calculator.

SEIA emphasizes that the forecasts used to set TOU periods should be broadly representative of the conditions expected to apply during the period when the proposed set of TOU periods will be in effect. For example, if the goal is to set TOU periods effective for the five-year period 2017-2021, it makes the most sense to forecast conditions in 2019, the middle year of the five-year period. That year will be the most representative of the five-year period, and will be easier to forecast than 2021. The Commission should <u>not</u> place the most weight on a forecast of conditions in 2021, at the end of the intended five-year term of this set of TOU periods.

- ***Wholesale price data, by location and time, and estimates for the future.***
- ***MGC hourly forecasts.***

Response: Generally, SEIA observes that all GRC Phase 2 cases include proposals for marginal energy costs (MEC), marginal generation capacity costs (MGCCs), and marginal distribution costs (MDCs, perhaps at several voltage levels), because electric cost allocation and rate design in California are based on marginal costs. Marginal high-voltage transmission costs can be calculated from CAISO Transmission Access Charge data. Although the FERC does not use marginal costs to set transmission rates, these CAISO-level marginal transmission costs do indicate how CAISO TAC costs will change with variations in the demand for bulk transmission. Ignoring CAISO-level marginal costs would exclude a significant share of IOU costs from the analysis. As set forth in more detail below, SEIA recommends that proposals to revise TOU periods should present and consider the time-varying hourly profile of a utility's full set of marginal costs over the year, for those functions whose costs vary with customer usage and demand – i.e., generation, transmission (both CAISO- and IOU-controlled), and distribution. Beyond adopting the general concept that the choice of TOU periods should consider all marginal cost elements that vary with time and customer usage, in this rulemaking the Commission should not constrain the methodologies used to calculate or to allocate marginal costs, because those methodologies are integral to cost allocation and electric rate design as well as to setting TOU periods. Marginal costs always will be the subject of debate in GRC Phase 2 cases, and this more limited proceeding on TOU periods should not constrain future robust debates on the marginal costs and cost allocation used to set electric rates.

Historical wholesale energy price data is readily available from the CAISO's locational marginal price (LMP) data, by location. The historical pattern of energy prices, plus forward market data, can be used to estimate hourly marginal energy costs (MECs) on a forecast basis. Alternatively, production cost models can be used to forecast hourly energy market prices. Both of these techniques have been used to calculate MECs in GRC Phase 2 cases. PG&E also has used an econometric analysis of how CAISO market prices vary with adjusted net loads to forecast marginal energy costs in its 2015 RDW case.

Similarly, there are a variety of approaches to estimating and allocating MGCCs. A short-run perspective on generation capacity costs may emphasize near-term prices for resource adequacy capacity, for which there is only limited transparency in California. A longer-term perspective will consider the traditional measure of long-term capacity, the full fixed costs of a new combustion turbine, as the least-cost source of new capacity that can be added relatively quickly. Allocating the marginal cost of generation capacity to hours can use modeling of loss-of-load-probabilities (LOLPs) or loss-of-load-expectations (LOLEs), various numbers of top load hours, or peak cost allocation factors (PCAFs).[4]

GRC Phase 2 cases also develop marginal sub-transmission and distribution costs, typically based on regressions of long-term investments as a function of peak loads.

- ***Bill impact data for various customer classes and segments of customer classes.***
- ***Data on customer engagement with and understanding of various TOU structures. Customer understanding of key rate features (TOU periods, relative prices), customer persistence on the rate, customer acceptance based on different segments of customer class. Effect of technology on customer acceptance of and engagement with TOU rates, effect of automation on TOU goals of load shifting and customer satisfaction, effect of technology and automation on customer acceptance and load shifting response to complex TOU rate***s.

[4] The PCAF approach has been used for many years in PG&E's rate design as the measure of a customer class's contribution to peak demand. PCAFs also are used to allocate marginal T&D costs to time periods in the "Public Tool" model of the benefits and costs of distributed energy resources, developed by Energy and Environmental Economics (E3) for the Commission. PCAFs are a set of hourly allocation factors for the hours with loads that are within a certain percentage (such as 10%) of the annual peak load, with each hour with a load above this threshold load weighted by the amount by which the load in that hour exceeds the threshold. Thus, for example, the PCAFs for the loads at a substation can be determined using this formula:

$$PCAF_s(h) = \frac{(Load_s(h) - Threshold_s)}{\sum_{k=1}^{8760} Max[0, (Load_s(k) - Threshold_s)]}$$

where:

$PCAF_s(h)$ = peak capacity allocation factor for substation *s* in hour *h*,
$Load_s(h)$ = the load for substation *s* in hour *h*, and
$Threshold_s$ = 90% of the substation *s* annual peak load.

All hours where the substation load is below 90% of the annual peak are excluded from the calculation and have a PCAF of zero.

Response: Customer bill impacts and customer engagement should be central considerations in the design of new TOU periods, particularly if the new periods apply to existing customers who in the past have been served under a different set of TOU periods. SEIA responds to customer-focused issues in more detail in response to the Group B questions. SEIA recommends that a portfolio of optional rates will provide an opportunity for different rate designs to prove themselves out in practice and for rate design to address particularly challenging system conditions in a more focused way.

- ***Impacts on distribution system usage compared to transmission system impacts. Should TOU periods consider (net) loads at the customer's meter (which drive distribution usage) as opposed to (or in addition to) net loads measured further upstream?***
- ***Distribution system peak hours by circuit and/or by substation.***

Response: SEIA strongly supports looking at the time dependence of all elements of a utility's marginal costs, including distribution, in setting TOU periods, because the time dependence of peak loads on the distribution system is different than the time profiles of system loads or net loads. Loads at distribution substations tend to vary over a broader range of hours than system loads or net loads. Further, many of the peak hours for distribution system loads are in the mid-afternoon hours, earlier than the net load peaks at the system level. **Figures 1 to 4** below show the distribution of annual peak load hours and PCAFs (based on 90% of the peak hour load or above) at SCE's A-Bank (sub-transmission) and B-Bank (distribution) substations in 2015. These distributions tend to peak at from 3 p.m. to 5 p.m.

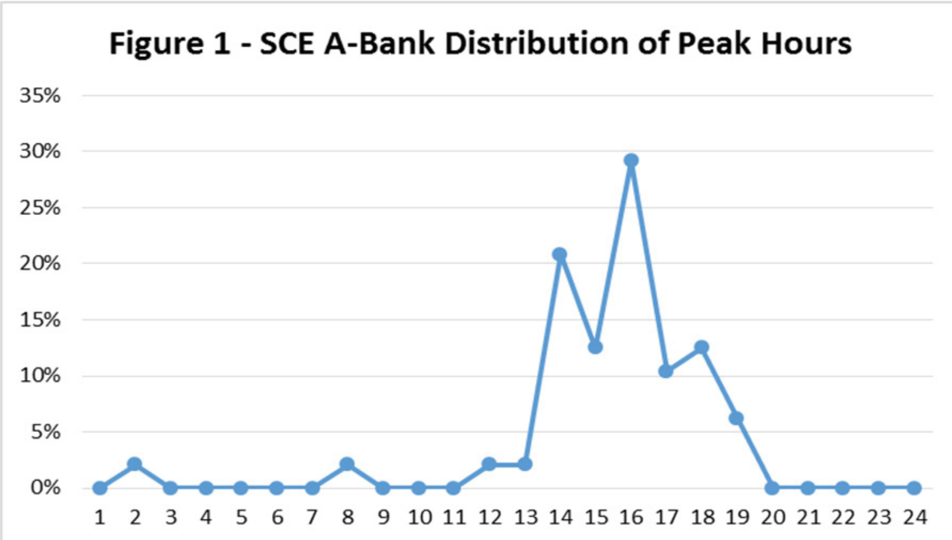


Figure 1 - SCE A-Bank Distribution of Peak Hours
35%
30%
25%
20%
15%
10%
5%
0%
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

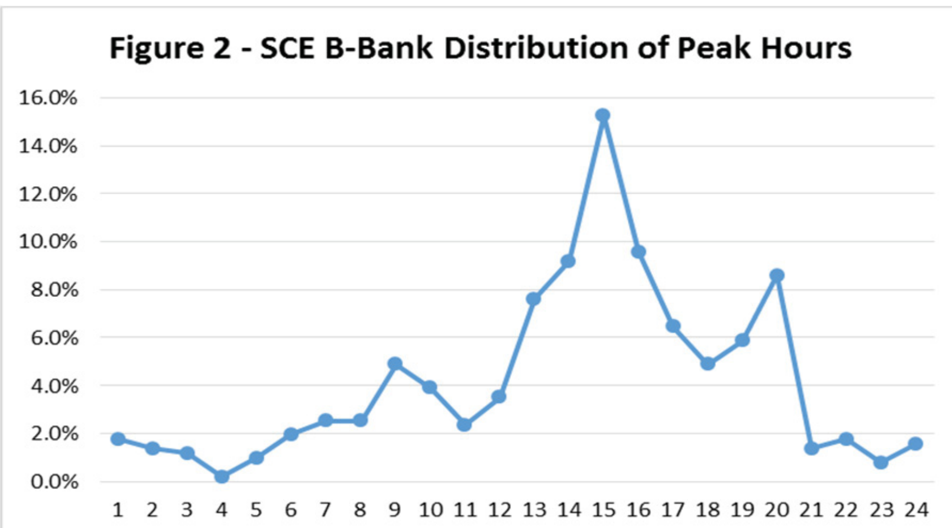


Figure 2 - SCE B-Bank Distribution of Peak Hours
16.0%
14.0%
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

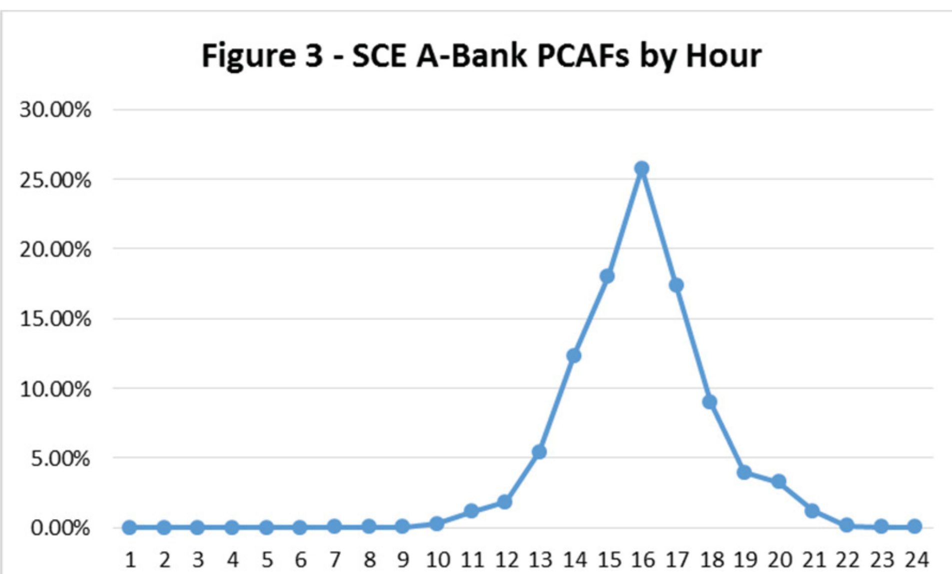
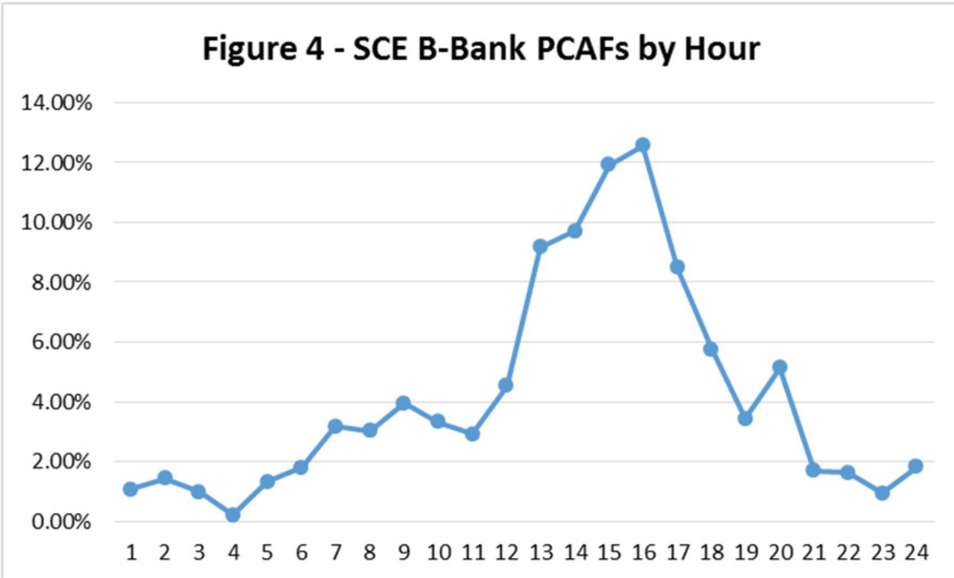


Figure 3 - SCE A-Bank PCAFs by Hour
30.00%
25.00%
20.00%
15.00%
10.00%
5.00%
0.00%
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

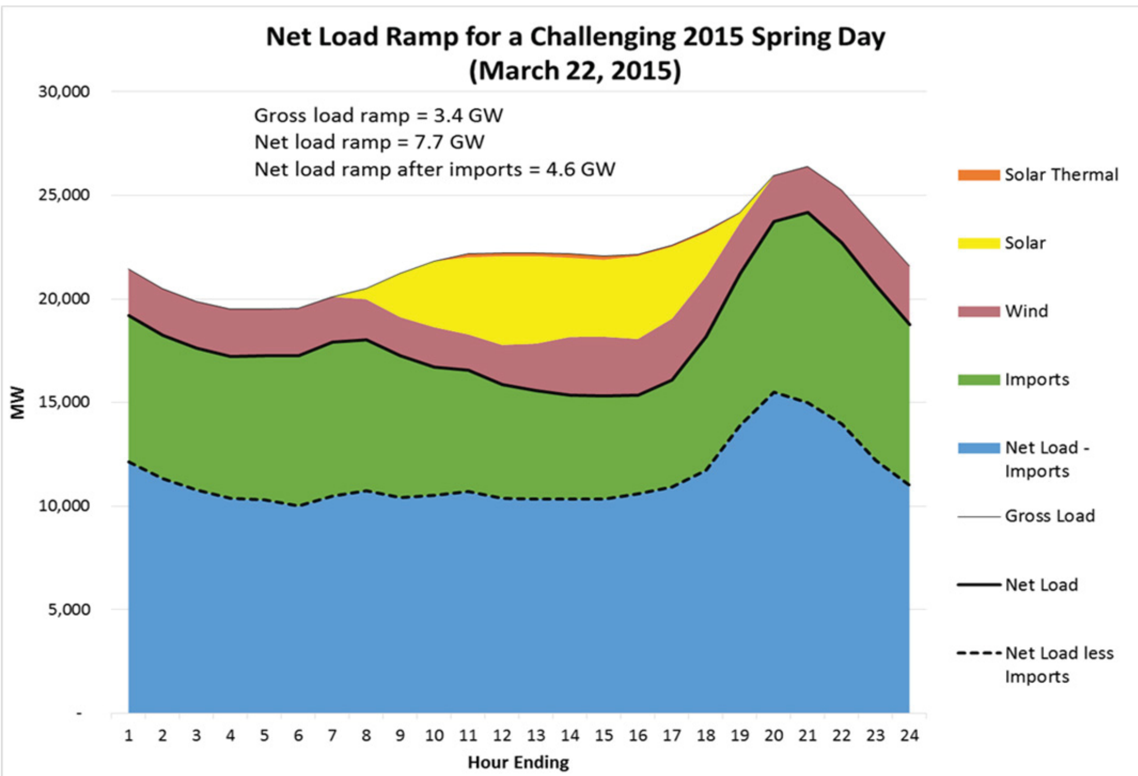


- ***Other measurements to identify hours that are operationally challenging for the system.***

Response: SEIA expects that system net loads (L4) or adjusted net loads (L5) will be instrumental in identifying months and hours with the most challenging ramping needs, as well as days when overgeneration conditions may occur. SEIA recommends that on-peak TOU periods should be centered on the hours prior to the net load peak that have the steepest up-ramps in net loads, as these are the hours in which unloaded, dispatchable generation must be available to meet the rapidly increasing marginal loads. The hours after the net load peak are not as critical, and do not need to be included in the peak period, as there will be more means available to reduce generation to meet the late-evening down ramp. Moreover, if there is a late-evening off-peak period beginning shortly after the net load peak, customers may more readily shift loads to the late evening to moderate the down-ramps (as opposed to the less-consumer-friendly option of shifting loads to the middle of the night).

- ***Forecast changes to market prices and load shapes under an expanded CAISO market.***
- ***Greenhouse gas emissions intensity associated with changing load shapes***.

Response: An expanded CAISO market will help to meet difficult operating conditions, such as steep evening ramps, by making more dispatchable regional resources available to meet these challenges. It is important to recognize that imports already contribute significantly to meeting net load ramps, as shown by the figure below, showing the contribution of imports (the green shaded area) to meeting the significant net load ramp on March 22, 2015.



An expanded regional market also can provide new and more diverse markets for excess renewable generation during certain times of the year, thus helping to resolve potential periods of overgeneration.

2. ***If you recommend using marginal generation capacity costs developed in IOU GRCs as an appropriate basis on which to set TOU periods, how should those costs be allocated to time periods? If by loads (e.g., Peak Cost Allocation Factors), which type of loads (see Table 1 above)? At what point should MGC data be considered stale (even if it was used in a prior GRC)?***

Response: The marginal generation capacity costs developed in IOU GRCs should be included in the marginal costs used to set TOU periods, but should not be the only marginal costs considered. Delivery costs comprise a major portion of electric rates and, as a result, marginal T&D costs also must be considered in determining which hours are the most important drivers of overall utility costs. SEIA recommends that the components of marginal costs should be allocated to the hours of the year using the allocation factors or market data listed in **Table 1** below. The allocators proposed in this table are specific to SCE but can be readily adapted to the other two IOUs as well. These allocators should be the same as, or reasonably similar to, the allocators used to spread marginal cost revenues among the utility's customer classes in its cost allocation and rate design, so that there is reasonable consistency between the choice of TOU periods and the resulting rates.

Table 1: *Allocation Factors for Marginal Cost Components*

Component	Allocator	Explanation
Marginal Energy	CAISO hourly DLAP prices	DLAP prices include congestion and loss impacts on the CAISO system
Generation Capacity	Allocator based on LOLP or contribution to peak net load or adjusted net load	Marginal generation is dispatched to meet net load or adjusted net load
Transmission Capacity	Allocators such as PCAF measuring contribution to coincident system peak	Transmission system peak usage is typically coincident with system loads.
Sub-transmission	PCAFs based on A-Bank substation loads	Allocator based on loads within 10% of peak load at each substation.
Distribution	PCAFs based on B-Bank substation loads	Allocator based on loads within 10% of peak load at each substation.

3. ***Using the data sources discussed in response to question 1, what analytical methods should be used to determine appropriate TOU time periods? Please provide a detailed response.***

Response: SEIA recommends that the Commission select TOU periods based on an examination of the hourly profile of <u>all</u> of the utility's marginal costs that vary with customers' usage and demand for electricity – that is, marginal generation, transmission, and distribution costs, excluding only marginal customer costs. Such a profile can be developed using the utility's marginal costs by function and the allocators shown in Table 1 above. As an example, SEIA has developed a total marginal cost profile for SCE, for both the summer (May-September) and winter (November – April) months, as shown in **Figures 5 and 6** below. These profiles are based on the marginal costs and allocators listed in **Table 2** below, using 2015 load data and SCE's filed marginal costs for 2015 in its last GRC Phase 2 proceeding (A. 14-06-014).

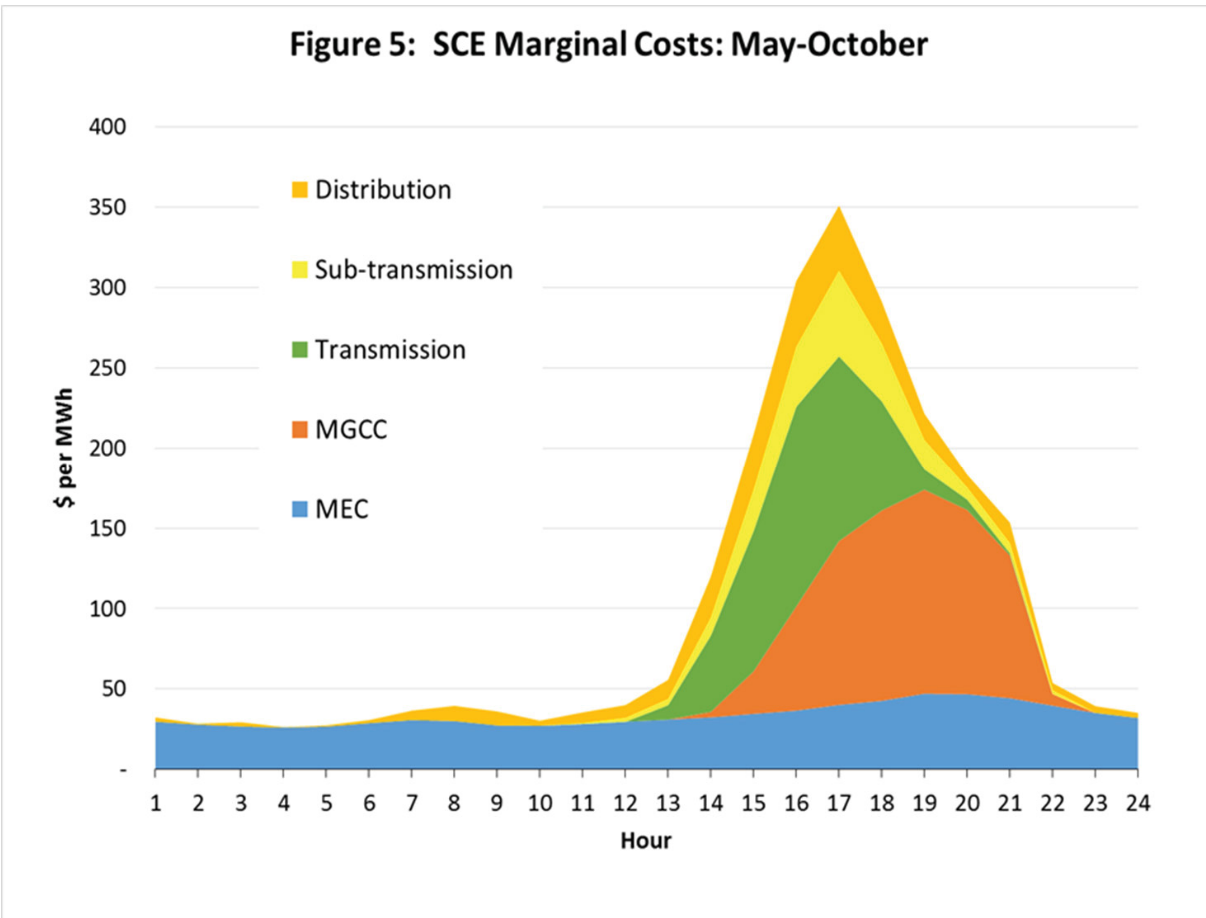


Figure 5: SCE Marginal Costs: May-October
400
350
300
250
200
150
100
50
-
$ per MWh
Distribution
Sub-transmission
Transmission
MGCC
MEC
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

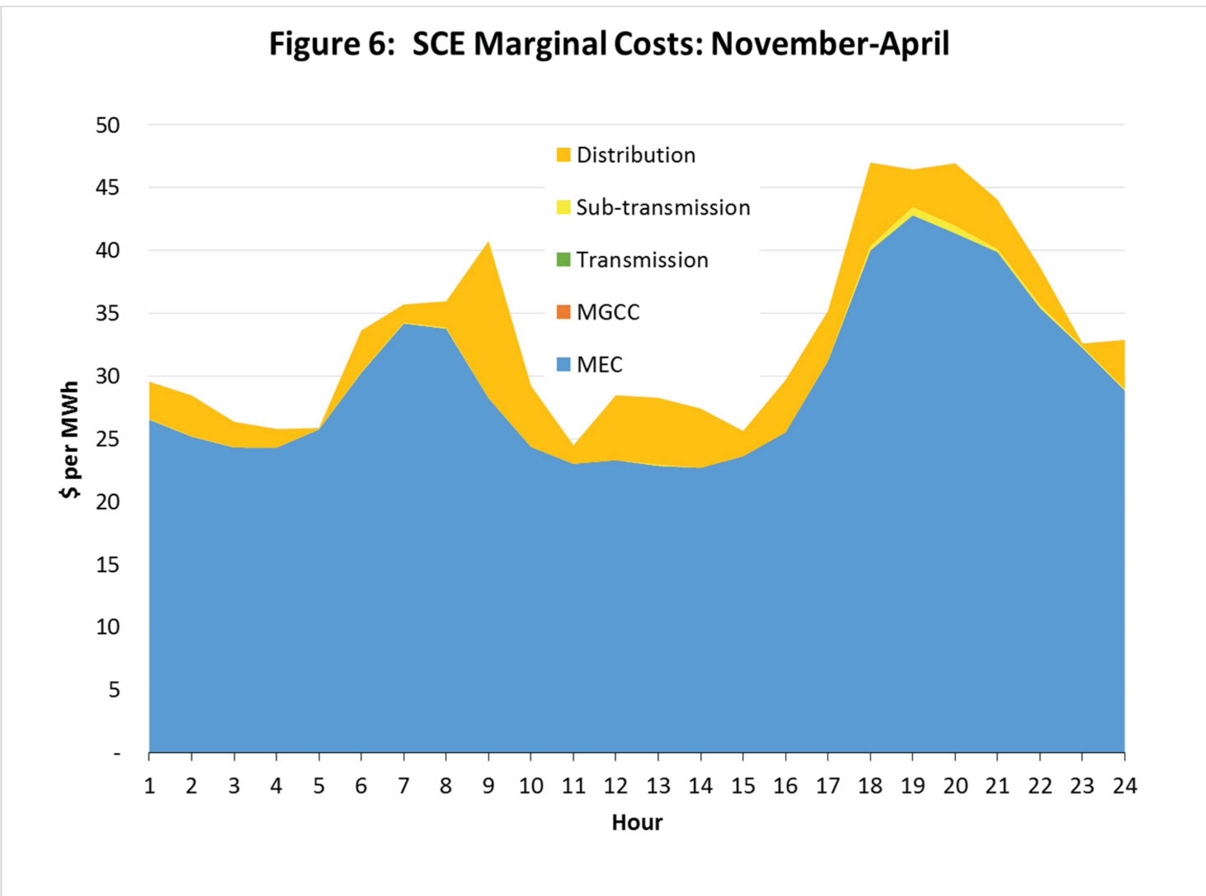


Figure 6: SCE Marginal Costs: November-April
50
45
40
35
30
25
20
15
10
5
-
$ per MWh
Distribution
Sub-transmission
Transmission
MGCC
MEC
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Table 2: *Assumptions for SCE Marginal Cost Profiles*

Component	Allocator	Value
Marginal Energy	CAISO hourly DLAP prices	MEC = 2015 SCE DLAP Day-Ahead CAISO energy market prices
Generation Capacity	PCAFs based on SCE net load in 2015	MGCC = \$120/kW-yr[5]
Transmission Capacity	PCAFs based on SCE system load in 2015	Transmission MC = \$87/kW-yr[6]
Sub-transmission	PCAFs based on A-Bank substation loads	Sub-transmission MC = \$38/kW-yr[7]
Distribution	PCAFs based on B-Bank substation loads	Distribution MC = \$67/kW-yr[8]

4. ***What data, assumptions, and analytical methods should be used to determine the TOU time periods from the grid perspective during which it would be helpful for customers to modify their level of energy use? Ideally, what data should be obtained from CAISO to determine these periods? How often should this data be updated? What data is it feasible for CAISO to provide***?

Response: SEIA's recommended approach makes use of CAISO energy market prices, load data, and net load data, all of which are readily available on an historical basis. The CAISO itself does not need to provide this data, as it is readily available on the CAISO's OASIS website. These metrics also can be forecasted, using a variety of techniques such as, for energy

[5] SCE's filed MGCC in A. 14-06-014 (Exh. SCE-02 – *Marginal Costs and Sales Forecast*, at p. 25).

[6] This estimate of marginal CAISO transmission costs is based on a regression of the CAISO base transmission revenue requirement (TRR) used in the Commission's NEM 2.0 Public Tool model over the 2012-2050 period, as a function of CAISO coincident peak demand over the same period. The TRR data used in this regression excludes the costs in the Public Tool for "policy-driven" CAISO transmission expansions designed to access RPS renewable resources. The resulting marginal CAISO transmission costs are \$87 per kW-year in 2015 \$. See *Proposal of the Solar Energy Industries Association and Vote Solar for a Net Energy Metering Successor Standard Tariff*, filed August 3, 2015 in R. 14-07-002, at pp. 23-24.

[7] SCE's filed marginal sub-transmission and distribution costs in A. 14-06-014 (Exh. SCE-02 – *Marginal* Costs *and Sales Forecast*, at p. 34).

[8] *Ibid*. SEIA has assumed that 75% of SCE's marginal distribution costs of \$89 per kW-year are time-dependent. SEIA recognizes that 100% of SCE's marginal distribution costs may not be time-dependent. PG&E has long recognized that a portion of its marginal distribution costs are time-dependent – basically, its primary distribution and substation costs. These are typically 70% to 80% of PG&E's marginal distribution costs.

prices, production cost models or analyses of forward market prices. SEIA anticipates that modeling of how energy prices and net loads may change with an expanded regional market will be a particularly useful contribution from the CAISO to inform future analyses and deliberations on TOU periods. As discussed above, SEIA strongly recommends that TOU periods should be set for five-year periods using forecasts of conditions in the middle of that period, i.e. using projections for 2019 for TOU periods to be effective from 2017-2021.

5. ***Based on the data and methods you recommend in response to Questions [1 – 4], how many seasons should be defined for the purpose of setting TOU rates and which months should be included in which seasons? Please provide detailed support for your response. If applicable, describe the potential benefits of defining additional seasons for TOU rates and TOD factors.***

Response: For TOU rates that are designed to be the default or are intended to be selected by a broad group of customers, SEIA strongly recommends the relative simplicity of two seasons – winter and summer. Figures 5 and 6 above indicate the significant differences in the marginal cost profiles for SCE between the summer and winter months. More complex, optional TOU rates designed to address specific system conditions such as spring overgeneration risks can consider adding a third season, although this also can be handled in a more targeted fashion through the optional overlay of the Discount Days concept that SEIA discussed in its April 6, 2016 comments in this docket.[9]

Maintaining a two-season rate structure on a default basis is also supported by the findings of the limited analysis available on load-shifting during spring periods of overgeneration. The *Joint Agency TOU Load Shifting Analysis* suggests that limited residential load shifting is possible and that piloting is needed given the limitations of current knowledge:

Even with aggressive rate design in targeted TOU periods, only modest increases in

[9] *See* pages 2, 7-10, and Table 1.

> residential loads during periods where overgeneration is being predicted should be expected, given current knowledge. This result is very uncertain, however, as consumer response to rates designed to induce usage has not been explicitly investigated, and thus further research is suggested, including pilots of rates specifically designed to increase usage during periods of expected surplus renewable energy.[10]

Likewise the *Analysis* finds that small and medium C&I customers, who recently moved to mandatory TOU rates, tend to conserve in all hours rather than shifting loads.[11] Among large C&I customers where load shifting to periods of overgeneration seems more probable, the *Analysis* notes that these findings may be exaggerated due to assumptions of price-driven behavior in this customer class.[12] These findings all caution against a move of customers to a three-season rate schedule on a default basis.

SEIA expects that an important issue in the selection of the months to include in each season is whether May and October will be summer or winter months. SEIA supports the use of a longer, six-month summer season (May through October). PG&E and SDG&E already use a six-month summer; SCE has a four-month summer. Using the SCE marginal cost profiles in Figures 5 and 6 as an example, there is not a significant difference in the time profile of SCE's marginal costs between a six-month summer (May-October) and a four-month summer (June-September), as shown in **Figure 7**.

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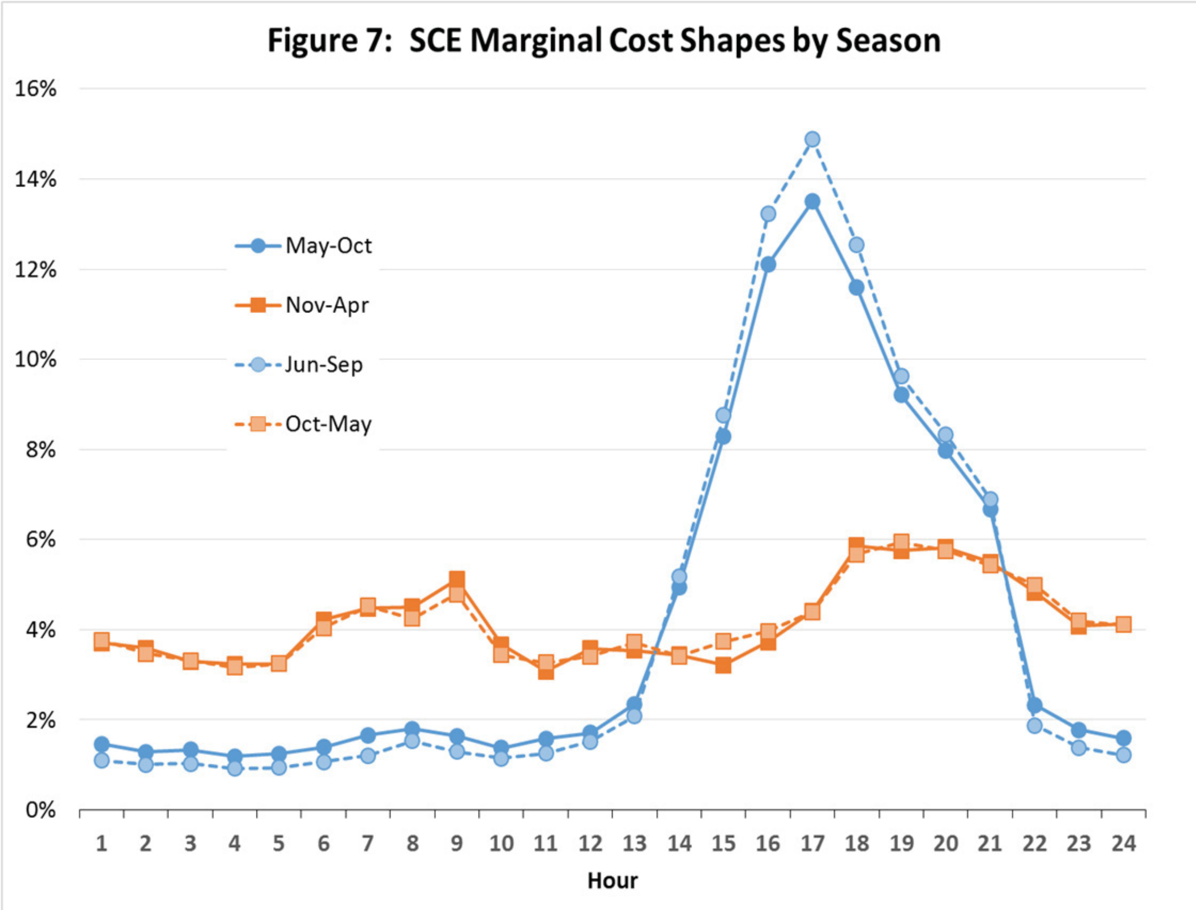
[10] Baker *et al*, at p. 23.

[11] *Ibid.*, at p. 34.

[12] *Ibid.*, at p. 19.



As the basis for choosing between these two possible summer seasons, the Commission should look to the studies of the expected impacts of climate change on California. As summarized by the California Climate Change Center, this work indicates that one principal impact of climate change will be longer and hotter summers, i.e. hot weather will start earlier in May and extend into October.[13] This trend is already apparent in historical weather records. We obtained 30 years (1985 - 2015) of data on daily high temperatures for 40 weather stations in the Los Angeles area, from the online data base of global temperature data at NOAA's National Centers for Environmental Information. We then determined the percentage of daily high measurements that

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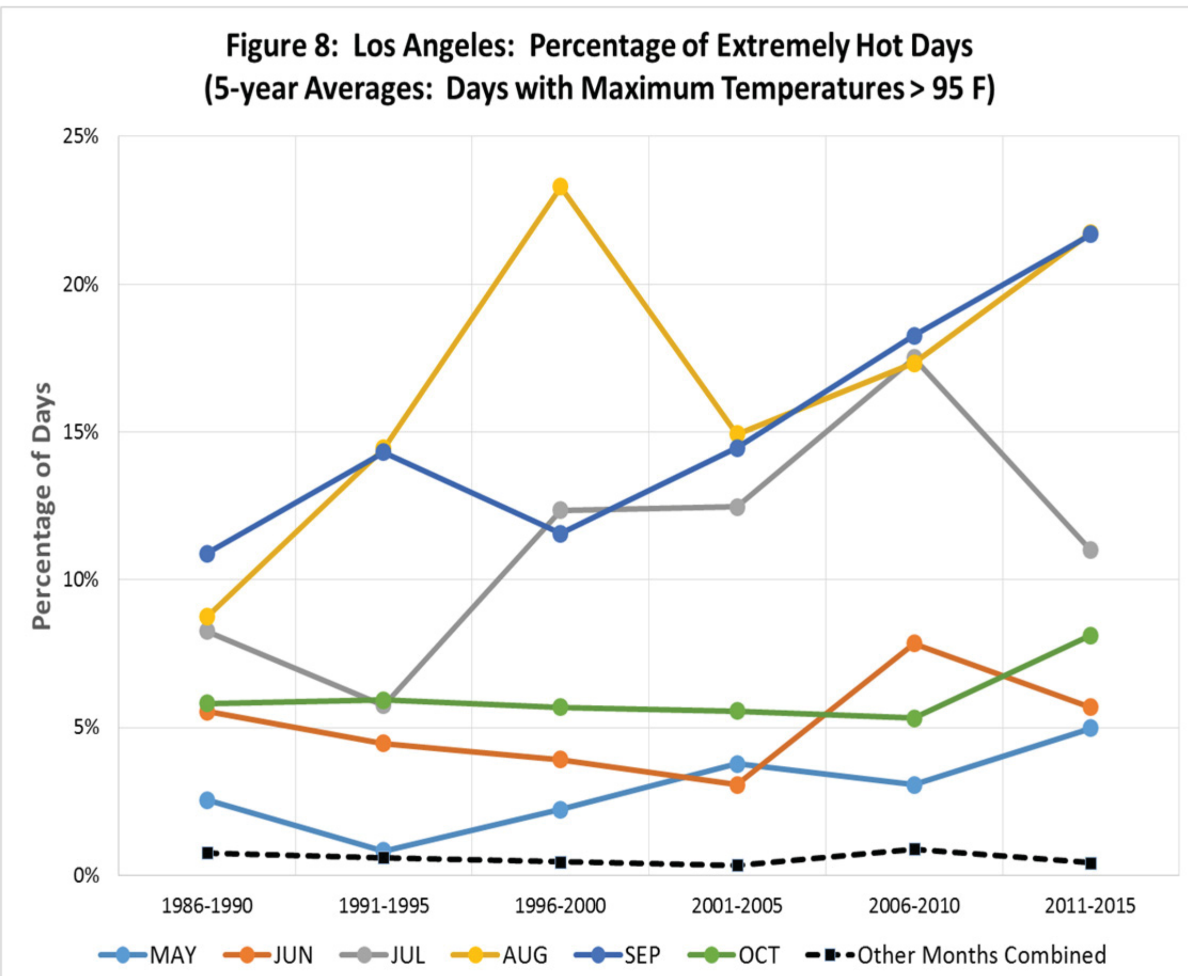
[13] See California Energy Commission, *Our Changing Climate 2012: Vulnerability & Adaptation to the Increasing Risks from Climate Change in California – A Summary Report on the Third Assessment from the California Climate Change Center* (2012), at p. 7 ("The third assessment confirms that climate change will increase demand for cooling in the increasingly hot and longer summer season.")

fell into SCE's "extremely hot" (greater than or equal to 95 F) category in its TOU-8-RTP schedule. The following **Figure 8** shows five-year averages for the percent of days in Los Angeles that fall into the Extremely Hot category. This analysis shows a distinct trend of more extremely hot days in May (the light blue line), and that May and October are now much like June in terms of the frequency of very hot days that cause peak electric demands. As a result, both climate models and historical trends suggest that a six-month summer will be increasingly important in order to capture all periods of hot weather in California. SEIA believes that this argues for the adoption of the longer, six-month summer season for all of the California utilities.



6. ***Based on your response to the previous questions, is the CAISO TOU Report (as described in Attachment 1 to the OIR and presented at the February 26, 2016 workshop), reasonable, either as proposed or with modifications? If you generally agree with the CAISO methodology, are the new TOU periods proposed by CAISO reasonable and consistent with their methodology or do you reach different conclusions?***

7. ***Are alternative methodologies necessary for identifying target time periods when an increase in electricity use is desired?***

Response: SEIA reaches different conclusions than the CAISO on how to approach setting TOU periods. SEIA appreciates that the CAISO's TOU Report focuses on conditions at the system level on the high-voltage grid that the CAISO operates. The CAISO's proposed TOU periods are complex, which is not surprising given the CAISO's detailed knowledge of the variations in system conditions that it faces. SEIA believes that, for widespread customer acceptance, the structure of most TOU rates will need to be much simpler than the TOU periods that the CAISO proposes, particularly if TOU rates are to become the default applicable to most small customers. Further, SEIA recommends considering the hourly profile of all utility costs, not just the generation costs on the CAISO system. While the CAISO's views on conditions on its system are important and should be factors in the choice of TOU periods, they should not be the only factors considered. A simpler structure for TOU periods is important for customer acceptance and understandability, and can produce most if not all of the system benefits that the CAISO identifies. Moreover, dynamic rate design programs such as Critical Peak Pricing and Discount Days[14] can be even more effective than static TOU periods at driving the beneficial customer behavior that the CAISO seeks.

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[14] *Ibid.*

8. ***In the future, should TOD factors used in evaluating and paying generation sources be related to the TOU periods in place at the time of contract execution? Why or why not? Does it make a difference if the TOU period is a "reverse demand" time period (time when excess generation is likely) or a peak time period?***

Response: TOD factors used in wholesale power purchase agreements (PPAs) should be related to the existing TOU periods in place at the time of contract execution, but may not be identical. For example, the choice of TOD periods should consider the wholesale generator's location on the grid. If the wholesale generator is interconnected to the transmission system, the TOD periods can be based only on the time profile of energy and generation capacity costs, based on the same MEC and MGCC profiles used to set TOU periods. Similarly, if the wholesale generator is interconnected to the sub-transmission system, the TOD periods can be based on the hourly profile of upstream energy, generation capacity, and CAISO transmission costs. SEIA submits that building up all elements of a utility's marginal costs, from energy to generation capacity to CAISO transmission to sub-transmission and finally to distribution, as illustrated in Figures 5 and 6 above, will allow for the development of tailored TOD periods using the subsets of these elements that are appropriate to a wholesale generator's location on the grid.

B. Other Considerations for Designing TOU Rates

1. ***What principles should the Commission use in setting the TOU periods? Specifically, what factors would lead the Commission to adopt TOU periods that depart from the TOU periods that result from your recommended methodology?***

4. ***Should a menu of TOU rate period options be available to any or all customers, or should there be a single set of TOU rate periods for all customers? If a menu of options should be available, what factors would support Commission adoption of TOU periods that differ from the results of the load and/or marginal cost analysis?***

Response: SEIA's methodology for setting TOU periods relies on an analysis of all time-varying marginal costs, and also focuses on the most operationally challenging periods (i.e., the late afternoon/early evening ramp) rather than the net load peak. SEIA's illustrative rate designs in our April 6th filing recognize that different rate designs can meet system needs while accommodating different customers' ability to respond to TOU price signals. The rationales for both SEIA's TOU period marginal cost methodology, and the suite of TOU rates that SEIA believes should be available to customers, inform our answers to the Part B questions from the Scoping Memo. While SEIA's methodology for establishing TOU periods is based on a single set of marginal costs, it may be justified to design individual revenue-neutral rates with different time periods (peak, off-peak, shoulder, and super-off-peak) than those resulting from SEIA's methodology. TOU periods may also vary across different rate schedules in order to facilitate a customer's behavioral or technology-enabled response to the rates. While consistent principles and clear methodologies for setting TOU periods and rate designs is critical, so too is a process for balancing the competing goals of using a consistent methodology to define new time periods and providing certainty for customer investments. SEIA believes that changes to TOU periods should occur as part of utility general rate cases and that customers should be able to stay on rate schedules with grandfathered TOU periods in order to provide certainty for investments in technology that are intended to respond to TOU period price signals.

TOU periods and seasons may vary across rate schedules and may differ from periods established by the strict application of a marginal cost-based methodology, such as the one proposed by SEIA. The Commission has previously considered factors that would support Commission adoption of TOU periods that differ from marginal cost analysis. As stated in D.15-07-001 the Commission determined that it is "…more important to ensure customer acceptance of the new rate structure and understanding of the directional price signal. The TOU Lite structure will be more acceptable to customers, less volatile, and avoid other potential issues."[15] Indeed, analysis done for PG&E suggests that residential customers would prefer to trade a shorter on-peak period for a longer one, in exchange for a lower rate differential.[16]

While the Commission has determined that it is admissible for TOU periods to deviate from those periods identified by marginal cost analysis, it also should be noted that the same marginal generation and distribution cost analysis could support multiple rate options with differing TOU periods. For example, more complex rates could have shorter, more targeted "super-peak" periods or an "inner summer" season, with shoulder periods capturing the adjacent high cost hours outside of those super peaks.

The Commission's earlier reasoning also informs our view on how many seasons should be incorporated in TOU rates. Default TOU-Lite rates are better served with two seasons ("summer" and "winter"), which limits complexity, while optional rate schedules could include additional seasons, such as a third spring season targeted at the spring months when the operational challenges created by overgeneration and the duck curve's steep net load ramps are most acute.

To be effective, TOU rates will need to balance system costs with customers' ability to accept the price ratios needed to achieve significant load shifting. This balance is achieved by enabling customers to elect rates that can accommodate their ability to shift load. In this regard, a "TOU Lite" rate, which has two seasons and moderate differentials in rates between on- and off-peak periods, reflects the ability of most customers to meaningfully respond to new rate designs.

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[15] *See* D. 15-07-001, at p. 135-136.

[16] *TOU Rate Development Conjoint Research Report Among Residential Customers*, HINER & Partners, June 2014.

Although a simpler structure may not capture all of the features of the net load curve, it can incent customer behavior to shift load in ways that are generally helpful to system operators.

While the shoulder seasons (spring and fall) are where concerns about the "duck curve" are most acute, overgeneration and steep evening ramps occur because loads are light in these seasons due to limited air conditioning or heating-driven electricity consumption. Since space conditioning comprises the largest single electricity loads for many customers, its absence in the spring and fall means there are more limited appliance loads to be shifted from ramping periods to take advantage of super-off peak periods corresponding with typical periods of ample renewable generation. The findings of the Joint Agency TOU Load Shifting Analysis recognize the limited ability for load shifting during overgeneration periods. Accordingly, rather than creating a third season which subjects all customers to a super off peak period every day (which as a result would raise rates during the peak period), SEIA suggests that the first approach to mitigating overgeneration should be through the use of the "Discount Days" concept that SEIA has suggested in prior comments, or other optional rates which would implement a low rate on a static or dynamic basis to encourage midday consumption that is targeted at times when overgeneration is forecast or generally expected.

2. ***Should TOU rate periods remain fixed for some period of time before they can be modified or should change be triggered by the appearance of certain factors or thresholds? If so, what is a reasonable timeframe or what factors or thresholds should be considered to trigger a change? In the future, should a process other than rate design window or general rate case applications be put in place to evaluate and update TOU periods?***

Response: Changes to TOU rates should occur as part of GRCs, and implementation should allow for grandfathering of customers on rate schedules with existing TOU periods so as to provide certainty around investments in distributed energy resources. Changes in TOU periods historically have been done in GRCs because they impact many aspects of ratemaking, not just rate design. TOU periods are also integral assumptions used in calculating marginal costs and in allocating revenues among the customer classes, which are also key issues in a GRC. SEIA believes GRCs should remain the forum for determining whether time periods should change and that a separate process is neither needed nor desirable.

While the Commission has recently allowed the IOUs to address changes in TOU periods in rate design window (RDW) proceedings, SEIA strongly recommends that this practice not continue. RDW proceedings, which the IOUs can initiate every year, have traditionally been more limited in scope and confined to specific issues of rate design. As a change in TOU periods impacts the calculation of marginal costs and the allocation of revenues, stakeholders could be subject to the equivalent of a GRC proceeding every year for each IOU, and customers could potentially be subject to a change in TOU periods every year. Similar reasoning suggests that a new process should not be implemented to change TOU periods outside of GRCs.

This proceeding should not attempt to define triggers or thresholds that indicate when TOU periods should change. Even if such a trigger or threshold could be defined, there would likely be continual disagreement and debate over whether such a threshold has been met. Such disagreement and uncertainty would not only result in excessive expenditure of Commission and stakeholder resources, but, more importantly customers would be in a constant state of uncertainty regarding the underlying rate structure upon which their electricity bills are based.

3. ***If TOU rate periods change in the future, should customers served on existing TOU schedules be able to remain on those TOU periods for a set amount of time? If so, for how long? Or, should customers currently enrolled in TOU rates be required to change if new TOU periods are adopted? How do customers react to changes in TOU rate periods? How often should TOU periods be changed in light of customer reaction?***

Response: Regardless of the frequency of changes to TOU periods, providing customers with the certainty to make investments in distributed energy resources will be key to inspiring customer investments that help address system needs. If, for example, a customer chooses to install west-facing solar panels in order to take advantage of peak periods benefiting late afternoon generation, and then time periods change before the investment is recouped, that customer will have forgone the greater generation of a south-facing system while failing to achieve the expected return from higher afternoon rates. The same logic applies for other distributed energy investments customers may make in energy efficiency or demand response technologies.

In examining this issue, the Commission should take into account the varying circumstances of different customer groups and adopt grandfathering arrangements which reflect those distinctions. Primarily SEIA proposes that today's solar customers who have interconnected under the TOU periods which are currently in effect for each IOU be afforded grandfathering treatment which differs from customers who interconnect after new TOU periods are established in the future. The former should be afforded a longer grandfathering period in order to protect any investments they have made in distributed energy resources based on the current TOU periods. The need for investment certainty and the "desirability of ensuring that customers have an opportunity to receive a return somewhat consistent with their expectations," was stressed by the Commission in its determination that Net Energy Metering customers should be afforded a twenty year period to transition to the successor NEM Tariff; failure to maintain this policy would not be in the public interest.[17]

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[17] D. 14-03-041, p. 20. The Commission recognized the same principal again in D. 16-01-044, at pp. 100-101, to allow customers to have a uniform and reliable expectation of stability of the NEM structure under which they decided to invest in their customer-sited renewable DG systems.

A change in TOU periods such as those currently being contemplated by the IOUs, which will shift the peak period as much as five hours later in the day,[18] could have a significant adverse impact on the economics of solar customers who have made long term investments in reliance on present TOU periods.[19] Even a milder shift of two to three hours will negatively alter the economics of projects, the economic feasibility of which were premised on the current TOU periods. Accordingly, SEIA recommends that these existing customers be afforded a minimum grandfathering period of ten years, with a subsequent transition to the then-effective TOU periods. For example, after the initial ten-year grandfathering period, affected customers could be subject to on-peak TOU periods that shift later by one hour per year.

Ten years is SEIA's recommended grandfathering period for existing solar customers on today's TOU rates. For customers who install DERs on TOU rates in the future, SEIA observes that the Commission appears to have established a minimum grandfathering period of at least five years for TOU periods. SEIA recommends that the Commission, after establishing a minimum allowed grandfathering period of at least five years,[20] should explore differing lengths of time that customers can elect to maintain rates based on certain TOU periods, dependent on the customer class and the underlying rate structure. Statute and Commission precedent- suggest that 5 years should be a minimum period for grandfathering TOU periods. P. U. Code Section 745(c)(3) directs the Commission to "strive for time-of-use rate schedules that utilize time periods that are appropriate at least the following five years" when implementing default TOU rates. While this legislative directive is not mandatory, the Commission has previously

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[18] For example, SDG&E has proposed in A. 15-04-012 to shift its summer on-peak period from today's 11 a.m. to 6 p.m. to a much later 4 p.m. to 9 p.m.

[19] *See, e.g.* , Prepared Direct Testimony of R. Thomas Beach, A. 14-11-014 (May 1, 2015), pp. 26-28.

[20] The period of time would be measured from the date on which the customer commenced service under the old TOU structure.

determined that “there are excellent policy reasons for requiring a five-year forward-looking design for TOU periods for default TOU rates.”[21] As noted by the Commission, “[a] constantly changing TOU period would cause customer confusion. It would also make it difficult for customers to evaluate investments in energy efficiency improvements and rooftop solar.”[22] Accordingly SEIA submits that in the Commission’s further exploration of the issue as part of this proceeding, five years must be the minimum amount of time that a TOU customer can remain on an established set of TOU periods.[23]

The Commission should also explore the implementation of varying grandfathering periods depending on the underlying TOU structure. For example, customers willing to sign up for Critical Peak Pricing rates could be afforded a longer legacy period for the underlying TOU rate periods, with the understanding that CPP periods could be changed more frequently.

5. ***Should TOU rate periods be consistent across different utilities, or should they be utility specific? Should TOU rate periods ever differ by geographic areas within an IOU’s service territory? Should TOU rate periods differ by customer class or segment?***

Response: Given the fact that marginal generation costs may vary between IOU service territories and the pattern and level of distribution costs may vary between IOUs, SEIA does not believe that TOU rate periods need to be consistent among the IOUs. It also may be reasonable to differentiate TOU rate periods by customer class since inclusion of distribution system costs could yield different periods for different types of customers. For example, if large industrial customers are interconnected at the transmission level, their load patterns would not be

[21] D. 15-07-001, p. 143

[22] *Ibid.*

[23] Moreover, it should be noted that the Commission determined in Decision 16-01-044 (p.) that prior to implementation of default TOU rates for residential customers, a NEM successor tariff residential customer who takes any TOU rate (including a TOU pilot rate) prior to the implementation of default residential TOU rates has the option to stay on that TOU rate for a period of five years from the date the customer commences the TOU rate. See D. 16-01-044, p. 93

responsible for driving costs on the distribution system, and therefore, the TOU periods for those customers should not take distribution costs into account since changes to their load pattern cannot reduce those costs. Similarly, residential customers are interconnected at the secondary distribution level, and contribute to costs all along the system. Changes to their usage patterns can help mitigate costs throughout the system, and therefore their TOU periods should reflect the potential to reduce the full set of the utility's marginal costs.

The issue of geographically segmenting TOU periods within an IOU's service area was discussed by parties at the workshop held in this proceeding on May 5, 2016, with the general consensus that it would be overly complex to pursue. The concept of geographically determined TOU periods is distinct, however, from including costs that may be location-specific (like distribution costs) in the derivation of TOU periods. All marginal costs have some differences by location: CAISO LMP energy prices vary by location as a result of congestion; marginal capacity costs may be higher in constrained local reliability areas; and transmission costs are driven by location-specific constraints on the grid. The time profile of each marginal cost element should reflect the overall time-dependent pattern of those costs across the system; in this way, territory-wide TOU periods can be generally aligned with the profile of aggregate marginal costs for the utility.

6. ***Other than pilots, how do you recommend testing TOU rates for levels of complexity (in terms of price ratio, number of periods, length of peak period) that will ensure the needed level of customer engagement to achieve the TOU goals?***

The goals of TOU rates will not be achieved unless rates are designed to incent customer response that reduces system costs. An individual customer's response can be dampened either through rates that are too mild, or rates that are too complex. Accordingly, the best way to "test" TOU rates is to provide a suite of optional rates from which customers can choose, including a default TOU-lite rate and a set of more complex optional rates. This will allow customers to match their ability to shift load to the appropriate TOU rate structure. A natural experiment resulting from customers electing optional rates is particularly important given that the vast majority of today's TOU rate structures, and thus the studies of the impacts of those rates, have focused only on eliciting a response from customers to high on-peak rates during traditional summer peaks driven by air conditioning loads.

7. ***Should TOU differentiation be applied only to variable energy costs or to composite energy costs that include all fixed and variable components?***

Response: Whether utility costs are "fixed" or "variable" depends on your time perspective. In the long-run, few utility costs are fixed. In the short-run, a broader array of costs can be defined as "fixed." SEIA strongly favors a long-run perspective on marginal costs and TOU periods, due to the increasing importance of rates in driving customers' long-term investment decisions. As discussed above, the marginal costs for generation, transmission, and distribution are all "variable" in time, in other words, these costs are all driven by customer demand that tends to occur only during certain time periods. Accordingly, the only marginal costs that should be excluded from consideration in setting TOU periods are the customer-related costs closest to the customer (the meter, service drop, and billing services, for example) that clearly do not vary with usage and that are driven simply by the fact of being a customer. The Commission will review the issue of what costs are "fixed" or "variable" for residential customers in future GRC Phase 2 proceedings, as directed in D. 15-07-001.[24] Until that review is complete, the Commission should treat all utility costs except for customer-related costs as "variable" for the purpose of determining TOU periods.

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[24] *See* D. 15-07-001, at pp. 5, 191-*193*, and 303.

Finally, the Commission should recognize that TOU differentiation will be more effective and more cost-based if the TOU rate design emphasizes volumetric TOU rates instead of 15-minute demand charges. Given the focus of this proceeding on using TOU rates to respond to the duck curve, the Commission should recognize the ability of volumetric TOU rates to send a more effective price signal than demand charges for incentivizing customers to shift net load from periods of high system and net loads (the neck and head of the duck) to the periods of low net loads (the belly of the duck). This point applies to both large customers – who today typically pay relatively high demand charges and low volumetric charges – and to small customers whose rates are mostly volumetric today but who face pressure from the utilities to move to rates with significant fixed or demand charges.

On-peak demand charges reward customers for reducing their maximum demand during the on-peak hour, but they do not reward customers for marginal demand reductions at any and all moments within the on-peak period. Only volumetric on-peak TOU charges send that consistent price signal. As the duck curve becomes more pronounced, mitigating its impacts will be more effectively addressed by rates that send a signal to customers to reduce their demand at all peak times, not just during those times when their demand is at or near what would otherwise be their peak demand during the billing cycle. For illustration, assume a customer with demands during peak periods that vary between 200 kW and 500 kW. With demand charges, any approach that customer takes to respond to the price signal in their rates will target reducing the maximum demand to some new demand threshold – for this example, say 400 kW. The customer is likely to focus on shifting loads within the peak period in order to reduce the maximum demand, but not necessarily reducing the overall average demand during all hours of the on-peak period. Essentially, the problem with a demand charge is that it does not encourage this customer to undertake efficiency measures or otherwise change their consumption pattern at times when they are using less than 400 kW. By contrast, a volumetric TOU rate would incentivize this customer to reduce consumption at all times during an on-peak period when it is possible for them to do so, thus reducing their average demand over the entire on-peak period. It is the average, aggregate demand of all customers during peak periods that drive capacity-related costs, and volumetric on-peak rates send the most effective price signal to reduce such loads.

While one component of customer cost-causation is indeed their idiosyncratic 15-minute non-coincident demand, that factor is poorly correlated with cost-causation that is due to electricity use during on-peak periods of maximum system and net loads. Given the diversity of customer loads, and particularly as the duck curve becomes “fatter” and more pronounced over time, the Commission should move toward expanded use, for customers of all sizes, of volumetric TOU rates instead of the outmoded blunt instrument of 15-minute demand charges.

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