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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 (December 17, 2015)

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

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Pursuant to *Scoping Memo and Ruling of Assigned Commissioner and Assigned Administrative Law Judge* (Scoping Memo), issued May 3, 2016 at the California Public Utilities Commission (Commission), and *E-Mail Ruling Notifying Parties of Revised Comment Schedule and Workshop,* issued May 25, 2016, the California Solar Energy Industries Association (CALSEIA) respectfully submits the following comments.

1. Introduction

In this proceeding, the Commission seeks to develop methodology for determining target time of use (TOU) time periods, with particular consideration of data from the California Independent System Operator (CAISO). How these "target" TOU periods get applied to utility rate cases has not been concluded.

Other parties will offer comments on the methodology of using system data to develop rate structure. CALSEIA does not seek to duplicate or add to those comments, and therefore does not offer responses to the first group of questions in the Scoping Memo. In these comments, CALSEIA addresses the second group of questions relating to other considerations for designing TOU rates.

Rethinking TOU rate structure should be viewed as a means to facilitate the adoption of technology that enables customers to take active roles in grid management. The Commission should seize this opportunity to guide customers with advanced technology to use their resources for maximum grid benefit, while also maintaining TOU rate options that are reasonable for customers without advanced technology.

2. Responses to Questions

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? Possible principles and factors may include, but may not be limited to, those included in the Residential Rates Design OIR.

CALSEIA firmly believes the Commission should develop a TOU rate structure that sends strong price signals with a greater level of detail than has traditionally been used in TOU rates, and make the rate structure available to customers on a voluntary basis. This may be similar to the TOU period proposal offered by CAISO, modified to include distribution system considerations. A structure with four seasons and four types of time periods is acceptable for customers with automated demand response (ADR), such as energy storage and building energy management controls. Such an "ADR rate" would ensure those customers are using their energy management capabilities in ways that most benefit the grid.

It should be noted that the ultimate target of rate sophistication is real time pricing. CAISO's proposed TOU periods are a big step along the way to more sophisticated rate structure. Dynamic pricing will need to be developed after gaining experience with complex yet static TOU structure. The Commission should ensure that the methodology developed in this proceeding is a significant step along the path toward dynamic pricing.

At the same time that we take large steps toward greater sophistication in TOU rates, it is also essential to maintain a less complex TOU option as the default TOU rate for wide scale customer acceptance. The default rate can use some elements of the target TOU structure, but would have far less detail. Current TOU rate schedules have only two seasons and two or three types of time periods. Those are good limits for the complexity of the default tariff. Like the ADR rate, the default rate should take into account all marginal costs, including distribution system costs, and should consider ramping capacity costs in addition to peak capacity costs.

In other words, the ADR rate should hit a bulls-eye on the target structure, and the default rate should take steps from the current structure toward the target. This builds on the first ratemaking principle in the 2015 decision restructuring residential rates. That principle states: "Offer a menu of different residential rates designed to appeal to a variety of residential customers, with different time periods and rate differentials."[1] Expanding that principle for the purposes of this proceeding leads to two principles:

- TOU rate structure should facilitate enabling technology by offering strong price signals that customers with automated demand response can respond to.
- Each utility should always make at least two TOU rate options available to

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1 D.15-07-001 at 176.

all customers, one that encourages ADR customers to operate their resources for grid benefit and one that sends accurate but less precise signals without having unreasonable bill impacts on non-ADR customers.

Another important consideration is that customers must be able to count on a reasonable level of stability in rate structure. Customers deciding on investments in onsite energy solutions face a great deal of uncertainty. This includes their future electricity consumption levels and patterns, performance of the distributed energy resource, construction and interconnection challenges, and future rate structure. Customers must be fully cognizant of the fact that rates can and do change, but there also must be a minimum level of predictability. In D.15-07-001, the Commission found that net energy metering (NEM) customers should be able to count on the rate structure for five years before being forced "to determine how to respond to new TOU periods."[2] Stated as a ratemaking principle, the Decision found:

> TOU tariffs should include a legacy provision that allows subscribers to remain on their existing TOU tariff (with its original TOU periods) for at least five years. When TOU tariffs are closed, they must be discontinued gradually. The discontinued tariff should first be closed to new customers. Existing customers (legacy tariff customers) should be permitted to remain on their TOU tariff for at least five years, with the ultimate duration of the tariff to be determined in future proceedings.[3]

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2 *Ibid.,* Finding of Fact 143.

3 *Ibid.* at 177.

In this proceeding, the Commission should find that such a minimum protection is necessary for both residential and non-residential customers, and that five years is an absolute minimum. When a customer invests in a 25-year asset, it is necessary to make predictions for savings over the life of the system. Five years of rate stability is much less than customers would like to make informed decisions.

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? Explain your rationale, including how it is consistent with the data, ratemaking principles or factors, and existing law identified in this proceeding.

Updating TOU structure with new methodology based on CAISO data can be achieved in this proceeding and will not need to be revisited on a regular basis. Once that is done the first time, there will not be a need to reinvent the methodology repeatedly. Future changes to TOU structure can be handled in GRCs. However, moving toward more sophisticated rate design will be an ongoing process that goes beyond TOU periods. CALSEIA recommends closing the instant proceeding upon issuance of a decision and opening a new proceeding on the Commission’s own volition to consider dynamic pricing after experience is gained from customers’ reactions to more complex TOU structure. The date for that future proceeding does not need to be prescribed at this time.

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?

There is currently a great deal of uncertainty about rate structure among customers and lenders that is impairing the ability of customers to adopt clean energy solutions. Proposed systems on good installation sites often cannot get financed because lenders are not confident the system will make economic sense for the customer for the 20-year term of a power purchase agreement. The NEM successor tariff decision, D.16-01-044, continued compensation for customer-generators based on the retail rate for customers that install solar through 2019. For that to have its intended impact of enabling solar located at the point of load, there must be some certainty to the underlying rates.

The rate stability principle quoted in response to Question 1 above envisions that utilities would keep legacy rates open for a period of time of at least five years after developing a new rate structure, i.e. "Existing customers (legacy tariff customers) should be permitted to remain on their TOU tariff for at least five years" after the rate structure changes.[4] New customers would go on the new tariff immediately, and all legacy customers would be moved onto the new tariff together at the end of the transition period. Another way to structure the transition is to allow customers to stay on their rate structure for five years following the installation of NEM-eligible systems. This would be more administratively challenging to implement, but would result in fewer customers on legacy schedules while maintaining fairness for customers who responded to rate structure by investing in distributed energy resources.

This is different from a scenario in which rate schedules can only change every five years and all customers switch to the new rate schedules when they become effective. If that were the case, some customers would begin service within

[4] *Ibid.* at 177.

the five-year period and be forced to change to a new rate schedule less than five years later. This would not uphold the finding that "Customers on TOU tariffs should be permitted to remain on them for up to five years."[5] Rate schedules can change more often than every five years if utilities propose changes and the Commission approves them, but those changes would only take effect for new customers, customers that have been taking service under their current rate schedules for at least five years since installation of a NEM-eligible system, and customers that have been on their current rate for less than five years but voluntarily switch to the new rate schedule.

In sum, the Commission must consider customer investments that are encouraged by price signals that existed at the time of the investments. For example, peak periods for commercial rate schedules are currently 11 am - 6 pm for SDG&E and 12-6 pm for SCE and PG&E. Customers have committed to clean energy solutions based on those time periods. All customers must be aware that rates are always subject to change, but there also must be the ability to have a reasonable expectation of consistency. Maintaining TOU structure for five years from the installation of a NEM-eligible system is a minimum level of regulatory certainty.

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?

As stated in the first principle from the residential rates decision, the Commission should "[o]ffer a menu of different residential rates designed to appeal to

5 *Ibid.,* Finding of Fact 142.

a variety of residential customers, with different time periods and rate differentials."[6] The Commission should apply this principle to non-residential classes as well.

Having a menu of options available enables utilities to give stronger price signals to a subset of customers that are able to respond effectively to those price signals. It is unrealistic to expect all customers to be able to respond to price signals that are as strong as needed to incent the installation of energy storage and other forms of automated load shifting and demand response.

For the ADR rate option, the Commission must consider the impacts of rate design on the financial prospects to the customer of storage adoption. TOU rates will not be the only revenue stream to support storage adoption, but they may be the most important one and it may be the one that steers storage deployment in the best direction. Currently, demand change mitigation for commercial customers is the primary revenue stream used to pay for customer-sited storage not designed for backup power, in addition to rebates from the Self-Generation Incentive Program. The customers that are most motivated to invest in storage to reduce demand charges tend to have load profiles with low load factors (i.e. more spikey than smooth), which results in a higher than average portion of the total bill coming from demand charges. These customers may not need to discharge their batteries frequently to avoid their highest spikes in usage, and those spikes may not coincide with system peaks or ramps. Therefore, storage used for demand charge mitigation may produce little benefit for load shifting to address system needs. Encouraging storage via TOU rate structure can result in better system benefits.

In D.14-05-033, the Commission concluded that customers with onsite storage

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6 *Ibid.* at 176.

paired with solar should not receive net metering credits for discharges from storage devices onto the grid.[7] Customers therefore cannot do TOU rate arbitrage by charging from the grid at a low cost time of day and discharging to the grid for credit at a high cost time of day. However, they can charge the storage systems during the daytime, either from a paired solar system or from the grid, and discharge to satisfy onsite energy consumption in the evening. This is a use case that the Commission should strongly encourage because it shifts load in response to system needs. For example, in a Super Off Peak period, it would be preferable to have solar production charging a battery rather than being exported to the grid. During the ramping hours, it would be preferable to have a home powered by onsite storage than drawing power from the grid.

Energy storage systems include control software that maximizes the customer benefits of the storage device, taking into account financial opportunities and real time building demand. A TOU structure with four seasons and four types of time periods is not necessarily a barrier. Other structures should be considered, but storage is, generally speaking, ambivalent to the complexity of the rate structure.

For storage customers, there are factors pointing toward shorter and longer time periods. What matters most to create value for storage is the differential between time periods. For that reason, shorter peak periods, super peak periods, and super off-peak periods are preferable for the ADR rate because allocating utility costs to shorter time periods leads to sharper distinctions between time periods. On the other side, customers need to have enough consumption in the peak period to take advantage of the load shifting opportunity. If time periods are too short, it will limit the universe of

7 D.14-05-033, Conclusion of Law 1.

customers that can find benefits from the TOU structure.

Another consideration is that under current tariffs storage systems are not very productive in the winter season. With narrow tier differentials, a minimal financial gain may not justify the wear on the battery to do any cycling at all. This leaves batteries underutilized for 6-8 months of the year, which can preclude the justification to make the investment in the first place. In the CAISO proposed TOU periods, the non-peak period during September through February is labeled Off Peak rather than Partial Peak, implying that the rate will be closer to the Super Off Peak than the Peak. This is positive for storage. The Super Off Peak on weekends throughout the winter is also useful, as is the Super Off Peak during weekdays in March-April.

Figure 1 shows the capital recovery period for battery systems if the battery systems are financially justified to the customer entirely with savings from TOU rates. Because batteries normally have a warrantied life of ten years, a capital recovery period of five years or less is necessary to motivate customer investment. Therefore, an average daily differential between the highest rate and lowest rate of approximately 33 cents/kWh is necessary to recoup an investment in energy storage. The storage device will charge from the solar system in lieu of NEM credits during the Super Off Peak period, if any, or Off Peak period. It will discharge to meet load during the Super Peak period, if any, or the Peak period.

Figure 1. Capital Recovery Period for Energy Storage Systems by TOU Rate Differential[8]

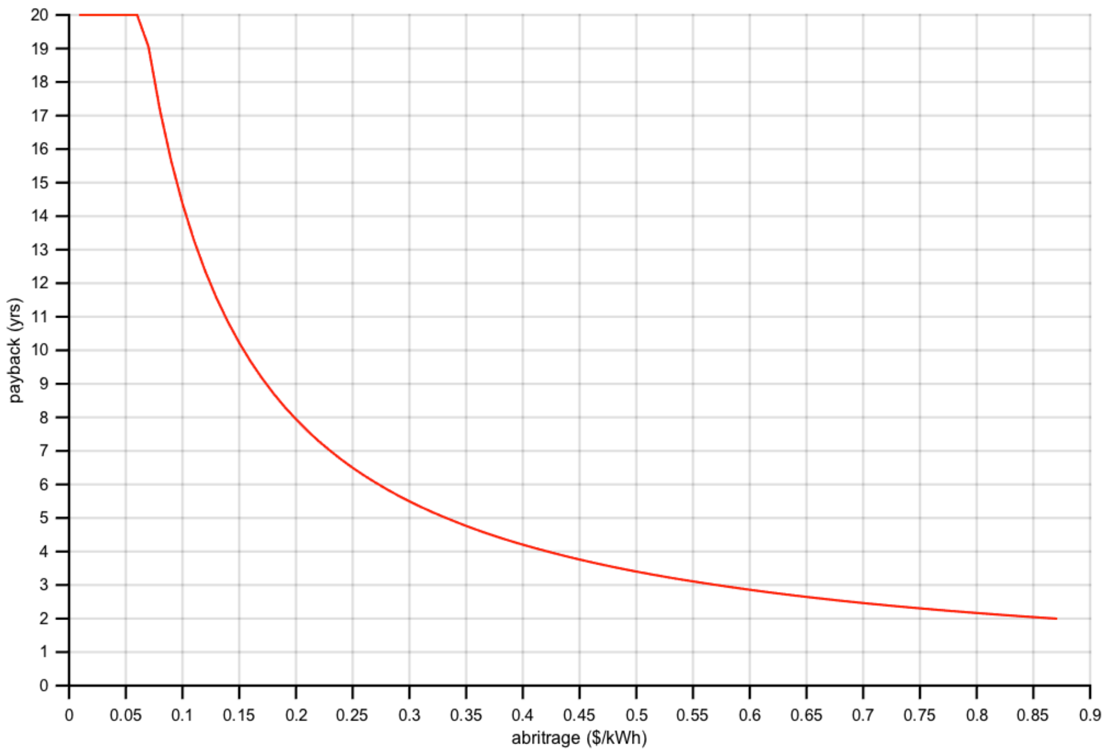

Table 1 presents a rate scenario using the CAISO proposed TOU periods that would achieve an average daily TOU opportunity of 33 cents/kWh. Clearly, this is a wider differential than most customers could manage reasonably. Even as a voluntary tariff it may be a larger differential than can be justified with cost causation, especially given that this assumes year round differentials of this magnitude and differentials in the winter season have tended to be very narrow. The point of the exercise is to gain a sense of scale for the value that TOU structure can provide for energy storage. A TOU rate with differentials this large could fund energy storage systems on its own. TOU rates with smaller differentials can contribute to the cost effectiveness of energy storage.

8 Data produced by CALSEIA member Growing Energy Labs, Inc. (Geli). Assumes an installed cost of $1000/kWh for the entire energy storage system, which is lower than current prices but expected to be achieved soon.

Table 1. Rate Scenario That Achieves Customer Cost-Effectiveness for Storage

TOU Period	Rate ($/kWh)		
Super Off Peak	$0.07		
Off Peak	$0.15		
Peak	$0.43		
Super Peak	$0.55		
Highest Daily Rate Differential	**Number of Days**	**Rate Differential**	**Customer Savings ($/kWh/yr)**
Off Peak to Peak	190	$0.28	$53.20
Super Off Peak to Peak	131	$0.36	$47.16
Off Peak to Super Peak	44	$0.47	$20.68
TOTAL	365		$121.04
Average Daily Differential		$0.33	

The Commission should take care to have realistic expectations of the value of TOU rates in changing the behavior of all customers. It is reasonable to expect that the majority of customers will dislike TOU rates and make modest changes to their behavior. TOU rates cannot be expected to solve the state's load shift needs. It may be more valuable to focus on getting a portion of customers to take major action than to try to get all customers to take significant action.

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?

TOU rate periods should differ by customer class. Because load patterns and local circuit peaks tend to be different for residential and non-residential customers, peak periods should be different for those classes. The May 3, 2016 scoping memo correctly states that time differentiation of distribution system costs exists and should be considered in this proceeding. A peak period that is earlier for commercial customers than for residential customers still gives commercial customers the incentive to conserve in the afternoon. In contrast, a commercial customer that is open during normal 9-5 business hours is unlikely to make significant changes to operations if the peak starts near the end of their operating hours. Also, because marginal generation costs and the level of distribution costs tend to vary between IOU service territories, TOU rates should differ across different utility territories.

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

It is important to recognize that "variable energy costs" is not the only component of utility costs that varies by time and/or volume. Most capacity costs are also variable in the long run. Exceptions are utility poles and service drops to individual customers. Most transmission and distribution capacity costs should absolutely be recovered with TOU differentiation. For truly fixed costs, it is a policy question for the Commission whether including them in TOU differentiation results in a rate structure with the price signals that the Commission seeks to achieve.

3. Conclusion

CALSEIA appreciates the opportunity to offer these comments and urges the Commission to adopt the recommendations herein.

Respectfully submitted this June 27, 2016 at Sacramento, California,

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