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**BEFORE THE PUBLIC UTILITIES COMMISSION**
**OF THE STATE OF CALIFORNIA**

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| 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) |

# COMMENTS OF CALIFORNIA FARM BUREAU FEDERATION ADDRESSING QUESTIONS RELATED TO ISSUES PRESENTED IN THE SCOPING MEMO AND RULING OF ASSIGNED COMMISSIONER AND ASSIGNED ADMINISTRATIVE LAW JUDGE

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## I. INTRODUCTION

Pursuant to the schedule established by ALJ McKinney, California Farm Bureau Federation ("Farm Bureau")[1] submits these Comments, which address the questions related to the issues presented in the Scoping Memo and Ruling of Assigned Commissioner and Assigned Administrative Law Judge dated May 3, 2016 ("Scoping Memo"). Farm Bureau appreciates the extensive discussions and comments which have been considered by the ALJ and CPUC staff members in order to refine the focus of this proceeding by posing appropriate questions. Farm Bureau has participated in the various workshops and hearings, finding them to be exceptionally constructive in creating a dialogue about the very challenging topic of how to address the impacts of and incorporate into customers' rate schedules the changes to actual and expected electricity supply and demand. Farm Bureau, like many parties, recognizes changes are necessary; however, those changes will need to be accomplished in a deliberative fashion in order to deliver thoughtful and clear communication to ratepayers regarding the changes to assure adaptation to revised TOU periods can be accomplished effectively.

Of keen concern to Farm Bureau has been the impact to ratepayers from the anticipated transition to new pricing periods. The Scoping Memo's recognition of customer engagement: "Fifth, consideration of customer acceptance is essential in TOU rate design."[2] underscores that as new TOU periods are developed, only if customers can respond in a pragmatic way to the changes, can many of the outlined goals be achieved.

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[1] The California Farm Bureau Federation is California's largest farm organization with approximately 53,000 agricultural and associate members in 53 county Farm Bureaus. California farmers and ranchers sell $44.7 billion in agricultural products annually, accounting for 9 percent of the gross state product, and hundreds of thousands of jobs in California. Farm Bureau's members expect to pay in excess of one billion dollars for their electric service.

[2] Scoping Memo, page 7.

Farm Bureau has worked closely in the past with stakeholders on behalf of its members as initial, successful efforts to incent customers to take service on TOU rates resulted in significant numbers of customers taking service on those rates voluntarily, and secondly, the mandatory transition to TOU rates was implemented. Our comments, although addressing some of the Scoping Memo questions identified in Part A, focus most predominately on Part B of the questions, which account for the customer acceptance aspects of TOU rate design. Because of various proceedings, Farm Bureau has had extensive discussions with members regarding their farming and ranching operations, and how the changing time periods will affect those operations. These comments provide an important opportunity to explain the implications of rate structures on our members' operations.

## II. METHODOLOGY OF SETTING TOU PERIODS

### A. The Starting Point for Analysis and Assessment of TOU Periods Is Important to Properly Gauge Necessary Changes

As a starting point to the analysis, it is important to develop an adjusted net load shape that reflects what the system load shape would look like under flat rates. This adjustment should be considered at least for large non-residential customers, whose load shapes are likely most influenced by the current TOU period definitions.

To illustrate the need for this analysis, consider a bundle of load that is 100% price-responsive. This load would be consumed wholly in the off-peak period and not at all in the midday on-peak periods, simply because the current TOU period definitions encourage this behavior. In the current net load analysis, this load appears to contribute to the problem of having insufficient load in the midday hours. However, the problem isn't the load, it's the current TOU periods which are incenting the "problematic" usage. To understand the true magnitude of the operational challenges that the CAISO is anticipating, and to be certain the true customer load shape is understood, it is therefore important to exclude this load from the net load curves (i.e., to consider it as flat load). In a more typical scenario in which price-responsiveness is less than 100%, only the portion of load that is price-responsive should be excluded from the net load curves.

There are several options that could be used to estimate the portion of load that is price responsive.

**Literature Review**: Demand elasticities could be estimated from studies that have already been conducted on load-shifting by specific customer groups in response to TOU rates. This approach would have the benefit of being off-the-shelf, but if studies are from other regions or are based on different TOU schedules or different TOU rate differentials, then are included in the California IOUs tariffs, care will be needed in applying the conclusions to the California IOUs.

**Data Analysis**: For customers who have recently migrated to TOU rates, it should be relatively straightforward to look at the impact of the TOU rate structure on load shapes by comparing load shapes before and after the migration. For customers that have been on TOU rates for many years, other approaches will need to be considered. For example, one could examine how customer load shapes shift during the weeks that rates transition from summer to winter rates and vice versa, or one could look at differences in load shapes between similar customers who are located in different utility service areas and therefore take service under different TOU period definitions.

In addition to the net load analysis (using the adjusted net load curve that reflects what the load shape would be absent TOU rates), the utilities' costs of service in different time periods should also be assessed.

### B. The Use of Marginal Generation Capacity Costs Should Be Specific to Each Utility (Question a.2.)

Farm Bureau supports the continued reliance on the use of marginal generation capacity costs developed in IOU GRCs. However, it is recognized there is no uniformity on the appropriate methodology or value for the utilities' marginal generation costs. By virtue of circumstances, the values are settled amounts, agreed to as part of broader settlement packages. For example, in the most recently settled Edison Phase 2 proceeding, marginal generation capacity costs were agreed to in the following manner:

> The generation marginal capacity cost shall be $108 per kW per year. (For revenue allocation purposes, SCE uses the value of $124 per kW per year, which reflects a 15% planning reserve margin.) The generation marginal capacity cost is allocated to TOU periods by SCE's relative LOLE measure. Unless specified elsewhere, for purposes of the rate credits provided for non-firm service, including price-based and reliability-based demand response programs, the avoided generation capacity value is also $108 per kW per year. (Generation marginal capacity costs by season and by TOU periods were set out separately in a Table.)[3]

In contrast, the most recent PG&E Settlement did not specifically call out the generation marginal capacity costs, although marginal energy costs are specifically set out in an Appendix.

> This MC/RA Settlement Agreement does not adopt any of the Settling Parties' marginal cost principles or proposals as the basis for the Revenue Allocation settlement described in Section VIII below. The Settling Parties agree that this MC/RA Settlement Agreement addresses all necessary marginal cost issues including the specific marginal costs to be used solely for the purpose of establishing costs where needed for customer specific

[3] Marginal Costs and Revenue Allocation Settlement, A. 14-06-014, dated August 13, 2015, page 8.

> contract analysis, including as required by Schedule E-31, and for analysis of contribution to margin for customers taking service under Schedule EDR. The marginal costs to be used for these analyses are provided in Appendix A to this MC/RA Settlement Agreement. Nothing in this MC/RA Settlement Agreement shall preclude any Settling Party from advocating for its preferred marginal costs in any other Commission proceeding or for the purpose of addressing specific rate design issues yet to be considered in this or other rate design proceedings.[4]

At this stage of development, Farm Bureau believes it is best to incorporate the data that the CAISO can provide to inform the marginal generation capacity cost data, allowing for the development of the costs as a basis for a new framework. As more consistent focus is brought forth in Phase 2s of a GRC to develop the costs, there may be noted commonalities raised, if that is found to be necessary. However, for the time being utilities should be allowed to rely on their own unique approaches.

## III. CUSTOMERS' ABILITY TO RESPOND ARE KEY CONSIDERATIONS IN THE ESTABLISHMENT OF TOU PERIODS

### A. Principles for TOU Periods (Question b.1.)

As common methodologies are being considered for utility-wide application, the underlying rationale for development of TOU periods should be appropriately considered at the forefront: "By target time periods, we mean time periods during which it would be helpful to the California power grid for customers to modify their level of energy use."[5] The underlying assumption is, of course, that customers will be able to adapt to newly created time periods, since without such an ability there is no point in having any time periods at all, then the goal becomes simply an exercise in capturing the costs of

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[4] Settlement Agreement On Marginal Cost and Revenue Allocation in Phase II of Pacific Gas and Electric Company's 2014 General Rate Case, A. 13-04-012, dated July 16, 2014, page 7.
[5] Scoping Memo, page 2,

delivering the energy. Thus, in addition to the rate principles captured in D. 15-07-001[6] to address residential rate design concerns, there should be a principle that recognizes time periods must be properly vetted to assure pragmatic solutions are developed which result in feasible adjustments by customers.

In examining the history of TOU rates for agricultural customers, it is instructive to recognize that as these incentive rates were established, the class adapted to them at significant levels. However, it should not be assumed that because customers initially adapted to TOU rates under the current structures that all will be able to adapt operations to any established TOU periods. As always, adaptation depends upon individual circumstances and customer operations. Since the process is just beginning, much is still to be learned.

Revising TOU periods must be recognized as a time of transition for a significant number of customers on the system. A substantial percentage of non-residential customers selected TOU rates as an option early in the development of the rates. Significant numbers have taken service for decades on the entrenched rates with established systems in place to respond to the periods, originally deemed as appropriate to direct demand on the system. For another significant segment, the transition has only recently occurred. For example, in SDG&E's territory, small agricultural customers are transitioning to TOU rates this year. In PG&E's territory, segments of agricultural customers have been transitioning to TOU rates over the last few years. That is the case for agricultural customers in Edison's territory as well. Although significant portions of the agricultural class load were on TOU rates, there was a considerable segment who did not

[6] Pages 27-28.

take service on TOU rates for varying reasons. In discussing the transition with members, the need for clear, distinct periods has been raised time and time again. Optimally, two seasons and two time periods (on and off) provide the clearest, manageable increments for effective responses. If too many seasons or varying time periods are developed, the management of the rate periods becomes so complex and difficult that effective response to price signals is undermined. At some point, too many variables and options may force customers to use energy without regard to time periods because it is impossible to adequately incorporate the periods into the operations. The complexities overwhelm customers, possibly forcing them to operate through the periods without adapting to them.

For example, question a.5 in the Scoping Memo, questions how many seasons should be included in the TOU periods. Currently there are two, which once begun continue until the other season commences. In contrast, the pro-forma periods provided by the CAISO[7] essentially sets up four weekday seasons and four weekend seasons, since the varying TOU periods are broken out into four separate monthly segments: September through February, March and April, May and June, and, finally, July and August. Even though May and June are the same as September through February, the two separate months should be considered as a distinct season since they are sandwiched between separate seasons. Although the CAISO has not recommended the patterns be used as “THE” rate design, the charts provide an example of how quickly the rates can become overly complex. The CAISO chart visually demonstrates the disruptions that arise when attempting to insert varying hourly periods within the seasons. Thus, even if a methodology can be developed which precisely reflects the costing

[7] R. 15-12-012, Order Instituting Rulemaking, Attachment 1.

elements, such a methodology should not necessarily lead to an adopted rate design to allow customer preferences and understandability to be effectively taken into account.

The issue of explaining complex pricing patterns in rate schedules should be considered in light of the broad range of customers all of the utilities serve on their systems. One of the reasons the mandatory transition to TOU rates for non-residential customers required extensive outreach and education activities can be attributed to that diversity. Unlike large customers, who may receive information, explanations and support from dedicated account representatives, small customers face the transition with generalized information through websites or call centers. If informed responses to changing TOU periods is to be expected from customers, they should also be provided adequate opportunities to understand any benefits and impacts.

### B. Durability of Established TOU Rate Periods (Question b.2.)

In any rate design process, it is essential that customers be provided stability and predictability about how they will be paying for their electric costs. Underlying the development of the evolving policies around energy usage is an expectation that customers will actively oversee and manage that usage commensurate with the price signals embedded in the rates. If one assumes customers are able and willing to make operational accommodations and/or investments to those changes, there must be a comparable commitment to customers that rate structures will be sufficiently durable to justify investment in time and resources. How long the rate structures should remain available will depend upon whether customers can remain on existing rates while new rates are implemented.

The question of how long TOU rate periods remain fixed should be informed by the process undertaken to educate customers about the changing TOU rate periods currently at issue. As agricultural customers transitioned to the mandatory TOU rates, the process was relatively straight forward because they were familiar with the framework since it had existed for so many years. In our view, the process of transitioning to different TOU periods may very likely create greater outreach requirements than simply transitioning customers to an existing rate option. Before plans can be made about the next step for changing TOU rate periods, an assessment and understanding of what transpires when the current transition occurs from long-established TOU periods to new ones will be instructive in developing a path forward for subsequent changes to those periods.

As for when changes would occur again, one has to keep in mind how long the existing periods have been in place and the evolution of events which precipitated those changes. Much analysis underlies the current movement to develop new TOU periods. One has to wonder if it will be a case of knowing it when you see it.[8]

### C. Managing Impacts to Customers from ongoing Changes (Question b.3.)

Underlying these series of questions, one might infer that the expectation that changes on the scale that is currently being discussed must be addressed. It may be too early to anticipate when and how the changes on the scale being considered here will be necessitated. Clearly, the reversal of a significant block of time, noon to 6 p.m., from an on-peak period to an off-peak period, is dramatic, particularly when coupled with the

[8] *Jacobellis v. Ohio*, 378 U.S. 184 (1964).

changing adjoining periods. It is as if the blocks of times customers have become familiar with were a deck of cards, which has been shuffled. It is difficult to fathom that future changes to TOU periods will prove to be as significant. However important it is to be prepared for potential changes, what must be planned for should be realistically assessed.

A complicating factor may be that the very act of establishing new TOU periods may shift targets in the future in a manner that will precipitate a need to manage the system in a different way than envisioned at this point. Although every effort is undertaken to predict how customers might respond to rates, customer responses can take indeterminate periods of time to materialize, driven by unanticipated consequences from the various elements of the rate structures. The increasing complexity of rate components render predictions even more difficult than in the past.

Customers will be loath to make investments or significantly adjust operations without the certainty necessary to estimate payback of costs. How customers react to the changes, we are learning, really depends upon the operations, as well as how much has been invested to respond to the parameters of a schedule, and what other factors drive the energy usage. The optimum outcome would be to allow customers to remain on existing schedules, until they choose to transition to whatever new rates are implemented. However, the complexities of electricity pricing create the risk for overburdening customers and administrators with too many conflicting choices. There is not enough information at this juncture to speculate about an appropriate time period for remaining on a schedule, other than to recognize that at least two rate case cycles should be the absolute minimum.

Phase 2 of utilities' general rate cases should continue to serve as the benchmark for revising rate schedules. Even though some elements of the Phase 2 cases vary from time to time, rate design, which may incorporate changes from cost allocation and other factors, remains a core component of the Phase 2. Once a rate design is adopted in a GRC proceeding, implementation may take more than a year, depending on how far-reaching the change is. Allowing at least one rate case cycle for the subsequent integration of the rate design with operations without change should be the absolute minimum.

### D. Diversity of Options Throughout the State Should Help Reduce Focused Usage (Questions b.4 and 5.)

There are so many factors attributable to the design of rates that it would be a disservice to customers and the system to unnecessarily hamper the effectiveness of rates by adhering to rigid structures. As indicated earlier, an important starting point of the rate design should be the designing utility's load and cost analysis. To the extent that data differs across utilities, that difference immediately translates to a rationale which supports different TOU rate periods amongst the utilities. Those differences exist under the current TOU framework, such by hourly block distinctions for on-, off- and mid-peak rates. Agricultural schedules demonstrate the differences for the basic components. SDG&E's Schedule TOU-PA summer on-peak is May 1 through October 31, 11 a.m. to 6 p.m. weekdays. PG&E's Schedule AG-4 summer on-peak is noon to 6 p.m., also May 1 through October 31. In reviewing the characteristics of the State's utilities, it would be difficult to argue for strict parameters that, for example, assume the same framework for PG&E and SDG&E's territory, unless the data presumptively confirms it to. Because the

TOU periods are likely to be at least similar, customers are not apt to be misled by distinctions across utility service territories.

In drawing distinctions within the utility service territory, whether by customer attribute, geography, or other elements, the assessment should be made on a case by case basis. Such assessments should link back to the underlying purpose of developing TOU periods, which is to incent customers to utilize their electricity to respond to identified goals in light of how the customers operate.

In the case of agricultural customers, rate design can significantly affect water usage, as energy needs are closely linked with irrigation for crops in the State. Such impacts have always existed, but have recently been placed in greater focus during the state's extended drought. Thus consideration of how the time periods impact other resources should be considered. The Butte County Water and Resource Conservation Department has recognized that the ability to manage and protect groundwater resources depends on having equitable and flexible agricultural electric rates. There the issue of the impact of electric rates on when growers irrigate creates verifiable consequences. When incentive rates are offered over a short period of time, growers are encouraged to irrigate at the same time. When growers in an area irrigate at the same time, the surrounding groundwater can be drawn down to a greater extent than when irrigation is staggered, which usage can affect the reliability of surrounding wells. In discussions with Farm Bureau members, it has been noted that similar effects are not limited to Butte County. In PG&E's service territory, customers have effectively used the AG-R and AG-V rates, which rates deviate from the current standard TOU periods and allow the opportunity to stagger irrigation schedules. The described scenario is only one example of the type of factors that support different TOU periods than the baseline set by the underlying load and cost analysis.

Furthermore, utilities and stakeholders may be able to gauge the ability and likelihood of customers' adaptability to the baseline periods. If customers are unable to adapt to particular frameworks due to operational constraints, it may be better to incent a level of responsiveness that meets those operational constraints. Forcing customers into frameworks which are unmanageable may leave them with no other option than to disregard the time periods. Agricultural irrigation practices provide another important example in this area as well. In discussing the revised TOU periods with members throughout the State, the impacts of drip and other forms of irrigation quickly brings the discussion into focus. Drip irrigation, while very effective in many ways, requires a great deal of management. The system can easily get clogged and water delivery impeded, delivery points may breakdown so that target trees or plants receive no water or excessive amounts, and the plethora of wildlife requires the operation to constantly check for holes in the delivery system. These impacts all mean that every time (multiple times within a month) an irrigation set commences, someone on the farm must check the integrity of the system by reviewing the delivery points. As a result, in the case of these subsets of irrigators, it will not be feasible to begin an irrigation set in an off-peak period that commences at night. Even if it were safe to operate and check the system at night, it is likely to be inefficient to check the system in the dark. As the individual utilities consider their TOU rate design, such pragmatic considerations will be of keen interest to our members and whether a path forward can be identified which can allow pragmatic ways to respond to price signals to meet system needs.

It is likely that other customer classes have pragmatic operational issues which justify deviation from the baseline periods. The success of the incentives with the existing TOU periods, indicates the need to spread the usage across the hours to create a diversity of demand. As the sources of generation become more homogenous, a diversity on the other side of the equation may be more important than required in the past.

### E. Customer Engagement Prior to Development of Rates Should be an Essential Factor Even if Pilots Are Utilized (Question b.6.)

Although data about how customers use energy on a system-wide basis is important and leads to assessments of potential gains, if customers can respond in a particular manner, pilots are not the only method of obtaining the information. Of course, development of rates responding to the needs of the system don't assure customers responsiveness without significant planning. However, rather than implementing pilot rates with hoped-for customer engagement, time and resources may be more effectively utilized to draw from targeted customer profiles that indicate potential benefits, much as marketing efforts seek information before launching new products. Although greater time will be necessary to assess and adjust customer engagement in responding to identified goals prior to the launch of a rate or schedule, in the long-term, a more productive expenditure of resources will be the likely result.

### F. How Broadly Should TOU Differentiation Be Applied Should Be Assessed by Customer Class (Question b.7.)

There may be instances where multiple components in a rate schedule provide for TOU differentiation, but there should not be a predetermined formula. Too much differentiation may create overly complex rates, rendering difficult assessment by customers about how to adapt operations. Such rate design considerations should take into account customer-related issues in the context of the GRC Phase 2, where rate design decisions will best be made going forward. Maintaining flexibility in development of rate designs will enable a broad range of customers to respond to TOU price signals.

## IV. CONCLUSION

There has been a building recognition in the past several years that the current TOU periods are not enabling the goals for which they were established, including appropriately reflecting actual and near-term expected electricity supply and demand. As evidenced through dialogue and debate in various proceedings, the challenge to be faced is the what, how and when of changing those TOU periods. As the Scoping Memo astutely recognized through its multiple questions about customer engagement and perspective, the transition to new periods cannot be accomplished without placing those periods within the context of customers' operations. The circumstances driving the establishment of new TOU periods are very different from those that originally established TOU schedules as purely voluntary, incentive-driven schedules. That the current TOU periods were decades in the making must be acknowledged as a factor that affects the how and when of transferring customers to new rates. Only if customers are willing and/or able to engage in the transition to new rates can goals associated with shifting demand be realized.

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