FILED
6-27-16
04:59 PM

**BEFORE THE PUBLIC UTILITIES OMMISSION 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 28, 2015)

OPENING COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) RESPONDING QUESTIONS POSED IN SCOPING MEMO RULING DATED MAY 3, 2016

JOHN A. PACHECO

San Diego Gas & Electric Company
8330 Century Park Ct.
San Diego, CA 92123-1530
Telephone: (858) 654-1761
Facsimile: (619) 699-5027
E-mail: JPacheco@semprautilities.com

Attorney for
SAN DIEGO GAS & ELECTRIC COMPANY

June 27, 2016

#306468

TABLE OF CONTENTS

I. INTRODUCTION 1

II. THIS PROCEEDING SHOULD IDENTIFY GENERAL REQUIREMENTS FOR FUTURE TOU PROPOSALS, INCLUDING METHODOLOGICAL PRINCIPLES IOUs CAN USE IN DEVELOPING FUTURE TOU RATE DESIGNS 1

A. The CPUC should provide guidance on data requirements for future filings proposing changes to TOU Periods 2

B. The CPUC should provide general guidance on methodology requirements for future filings proposing changes to TOU periods 3

C. The CPUC should provide general guidance allowing for unique IOU characteristics in future filings proposing changes to TOU periods 4

D. Guidelines should be applicable in future proceedings 4

III. SDG&E'S RESPONSES TO SCOPING MEMO QUESTIONS 5

IV. CONCLUSION 20

BEFORE THE PUBLIC UTILITIES OMMISSION 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 28, 2015)

OPENING COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) RESPONDING QUESTIONS POSED IN SCOPING MEMO AND RULING DATED MAY 3, 2016

I. INTRODUCTION

Pursuant to the May 3, 2016 Scoping Memo and Ruling of Assigned Commissioner and Assigned Administrative Law Judge ("Scoping Memo"), San Diego Gas & Electric Company ("SDG&E") hereby provides comments and responses to the questions posed in the Scoping Memo. As set forth below, SDG&E's comments suggest an overall approach to the issues raised in this proceeding and focus on specific guidance that SDG&E encourages the California Public Utilities Commission ("Commission") to provide as the main outcome of its final decision. In light of the Legislative mandates regarding time-of-use ("TOU") rates, continuing rapid growth of renewable energy, changing operational needs of the electric grid, and new patterns of customer energy use, such guidance will allow SDG&E and the other investor-owned utilities ("IOUs") to present well-formed and supported TOU rate design in future General Rate Cases ("GRCs") and/or Rate Design Window Cases ("RDWs).

II. THIS PROCEEDING SHOULD IDENTIFY GENERAL REQUIREMENTS FOR FUTURE TOU PROPOSALS, INCLUDING METHODOLOGICAL PRINCIPLES IOUs CAN USE IN DEVELOPING FUTURE TOU RATE DESIGNS

SDG&E generally agrees with the Scoping Memo's refinements to the scope of this proceeding and its focus on methodological principles, as opposed to specific rate designs or the setting of specific TOU periods. Based on such general principles and guidance, SDG&E and the other IOUs will have the base parameters necessaryto present data to set specific TOU periods in future GRCs and RDWs. Accordingly, SDG&E encourages the Commission in this proceeding to identify the basic showing IOUs must make in future applications (GRCs or RDWs) seeking approval of IOU-specific TOU periods. Although each such application will require refinements and/or detail not covered by the basic requirements established here, knowing these requirements in advance will facilitate more efficient and timely processing of future TOU period filings.

With these goals in mind, based on the workshops and data already developed in this proceeding and the goal of issuing a final decision before 2017, SDG&E respectfully suggests that this proceeding produce guidance in the following three areas, keeping in mind that this list is not meant to be proscriptive in what can be presented in future proceedings:

- Data Requirements;
- General Methodology; and
- Flexibility to Tailor IOU-specific TOU periods.

A. The CPUC should provide guidance on data requirements for future filings proposing changes to TOU Periods

The basic data that IOUs must provide in support of future TOU period proposals should be determined in this proceeding, keeping in mind that the unique nature of individual IOUs may require additional data, as discussed in subsection C below. SDG&E proposes that general guidance regarding the following data points be provided:

- granularity of data (i.e., hourly);
- basis for establishing net load (i.e., statewide or local or both);
- how forecast or historical data should be used; and

- what bill impact data should be presented.

Guidance in these areas will provide SDG&E and the other IOUs with the clarity necessary to avoid the rejection of future TOU period applications for lack of specific detail. For example, in SDG&E's 2015 RDW, the Commission rejected SDG&E's TOU period proposal based, among other things, on a lack of supporting data and use of certain forecast data (as opposed to historical data).[1] Although SDG&E did not agree with this outcome, its application was rejected without prejudice, and therefore, SDG&E requests that clear guidance in the foregoing areas be provided in this proceeding so as to ensure SDG&E's ability to meet its burden of proof in future TOU period applications. In addition, given the dependence on CAISO data, it will be critical to ensure that the data necessary to establish new TOU periods is readily available.

B. The CPUC should provide general guidance on methodology requirements for future filings proposing changes to TOU periods

The primary area of methodology guidance required for future TOU period proposals is related to marginal cost data. Such data is a key driver to determining appropriate TOU periods. Accordingly, SDG&E proposes general guidance confirming the significance of marginal cost data and how it can be used in conjunction with CAISO load data.

- marginal cost data should be the primary driver for TOU period definition;
- marginal energy costs should generally align with net loads (as shown in the CAISO's May workshop presentation);
- marginal generation capacity costs ("MGCC") should be used to identify the peak hours because they are aligned fairly closely to the CAISO-proposed peak hours;
- ramping should be included in the calculation of future energy or capacity costs, so as to provide accurate price signals to customers (consistent with the CAISO analysis focus on ramping); and

[1] See D.15-08-040.

- TOU period definitions should focus on average days, rather than infrequent events, such as over-generation events.

C. The CPUC should provide general guidance allowing for unique IOU characteristics in future filings proposing changes to TOU periods

Although the guidelines set forth above are generally applicable to each utility in terms of the basic showing required to propose TOU period changes, the upcoming Commission decision should also confirm the reality that there are differences among the IOUs that must be taken into account in determining specific TOU periods for each IOU and their respective customers. The following is a list of specific differences that should be accounted for:

- differences in loads and therefore net loads – specifically the CAISO data showing SDG&E having much lower loads in the 12 a.m. to 6 a.m. period due in part to a different customer composition (i.e., a relative lack of a large industrial base);
- differences in seasonal definition;
- differences in customer needs;
- differences in need for local capacity;
- differences in transmission constraints; and
- whether incorporation of distribution circuit peak loads are appropriate.

D. Guidelines should be applicable in future proceedings

Finally, the final decision in this proceeding should confirm that the adopted guidelines are to be used in future, as opposed to pending, GRC or RDW proceedings addressing TOU periods. For SDG&E, it is anticipated that the next applicable proceeding (after the currently pending 2016 GRC Phase 2[2]) would be its 2019 GRC Phase 2.

III. SDG&E'S RESPONSES TO SCOPING MEMO QUESTIONS

The goal of the Scoping Memo is to ensure that the Commission has sufficient context in which to make a decision on the relatively narrow area that is within scope of the proceeding (i.e., how TOU periods should be set and used in future rate designs proceedings). The first list of questions focuses on development of a methodology and data sources for identifying target TOU periods, including minimum data needs for IOU applications as well as ideal data. The second group of questions focuses on other aspects of TOU rate design. In particular, these questions focus on the customer acceptance aspects of TOU rate design. SDG&E's responses to each set of questions are set forth below.

Questions Regarding Methodology for Setting TOU Periods

1. The OIR, and parties commenting on the OIR, suggested the following data to support the development of a methodology for identifying target TOU periods.

[2] The TOU period proposals in SDG&E's currently pending 2016 GRC Phase 2 are based on Commission guidance set forth in D.15-08-040 and should not be subject to retroactive application of different requirements that might be adopted in this proceeding.

Table 1: Types of Loads

Nick Name	Data Basis
L1	Hourly Consumption
L2	Hourly metered load (net of "behind the meter" generation)
L3	Hourly load, net of Customer- and Distribution-connected DERs, measured at the substations (transmission interface)
L4	Hourly "net load" as defined by CAISO: "forecasted load and subtracting the forecasted electricity production from variable wind and solar resources."
L5	Adjusted net load (as proposed by PG&E): CAISO net load, net of nuclear and minimum flow hydro.

- Hourly metered load, net load, and usage data, disaggregated by location, customer class;
- Hourly wholesale supply data, disaggregated by location and type of generation;
- Estimated hourly load and supply for years through 2020;
- Wholesale price data, by location and time, and estimates for the future;
- MGC hourly forecasts;
- 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 rates;
- 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;

- Other measurements to identify hours that are operationally challenging for the system;
- Forecast changes to market prices and load shapes under an expanded CAISO market; and
- Greenhouse gas emissions intensity associated with changing load shapes.

a. Which data are relevant to setting TOU periods from a grid perspective?

TOU periods should reflect the costs to serve customers in the particular time periods - high cost hours in on-peak and super on-peak periods and low cost hours in off-peak and super off-peak periods. By aligning TOU periods with the cost to serve customers, customer actions to reduce their bills provide a system benefit and not a system cost. The recently completed *2015 California Demand Response Potential Study, Phase 1 Study Result,* presented April 11, 2016, found that TOU pricing could provide 1,200 MWs of load-modifying demand response by 2020, lowering the CAISO-expected afternoon ramps.[3] SDG&E believes the use of net load provides a simple metric to assess TOU periods and supplements utility-specific information on costs. System-wide data on hourly "net load," as defined by the CAISO and labeled L4 in Table 1 for the most recent year and a forecast year as provided by CAISO, is the most relevant data for setting TOU periods from a grid perspective and is reflective of statewide energy and capacity costs (which should include ramping costs).[4] As the CAISO showed in the May 5, 2016 workshop, net load provides a good correlation with day-ahead energy prices and highlights the system ramping needs that result in the need for flexible capacity.[5] As SDG&E showed in its

---

[3]Peter Alstone, Jennifer Potter, Mary Ann Piette, Peter Schwartz, Michael A. Berger, Laurel N. Dunn, Sarah J. Smith, Michael D. Sohn, Arian Aghajanzadeh, Sofia Stensson, and Julia Szinai, *2015 California Demand Response Potential Study,Phase 1 Study Result*, presented April 11, 2016, slide 68, Business-as-usual scenario assumptions with the on-peak period being 4 pm – 9 pm, consistent with the CAISO-proposed time periods.

[4] As noted above, however, given the dependence on CAISO data, it will be critical to ensure that this data will be readily available.

[5]Clyde Loutan, John Goodin, Delphine Hou, and Jordan Pinjuv, CAISO's Proposed TOU Periods to Address Grid Needs with High Numbers of Renewables, May 5, 2016 presentation, slides 8-12.

April 29 filing, periods of high net load also correspond to periods of likely system capacity needs.[6] Net load is easy to visualize and correlates well with statewide marginal generation costs ("MGC").

Utility-specific data are also relevant to setting TOU periods from a grid perspective and should also be taken into account in utility-specific rate proceedings. To the extent loads (or net loads) are sufficiently different than the statewide results, it may lead to adjustments to the TOU periods suggested by statewide net load analysis (e.g., SDG&E's different load profile relative to peak for 12 a.m. to 6 a.m. in non-summer months.)[7] To the extent there may be a need for local capacity, Loss of Load Expectation ("LOLE") analyses of the local area or transmission access charge area should be considered to see if the peak hours differ slightly from the state as a whole. Likewise, marginal energy costs should be analyzed to see if transmission constraints lead to slight changes in the times of high and low demand compared to TOU periods based on statewide net load analysis. For example, projected and actual energy prices in the month of May differ for the IOUs.[8]

Lastly, distribution system peak hours by circuit should also be analyzed to see if they can be aligned with statewide TOU periods. There are two aspects to the analysis: (1) whether historical distribution peaks are sufficiently aligned with on-peak TOU periods by month and hour to be considered in defining the on-peak period; and (2) whether super off-peak periods are sufficiently aligned with a few or no projected distribution circuit peaks. Super off-peak periods should not lead to a significant number of potential circuit overloads and the need to build added infrastructure.

---

[6] Appendix B RECAP modeling results showed a relative need for capacity in the highest net load hours of 4 pm – 9 pm.
[7] Clyde Loutan, John Goodin, Delphine Hou, and Jordan Pinjuv, *CAISO's Proposed TOU Periods to Address Grid Needs with High Numbers of Renewables*, May 5, 2016 presentation, slide 2.
[8] Robert Levin, *Comparison of Utility MGC* Data*, May 5, 2016 presentation, slide 3.

b. 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.

The type of data the CAISO and the IOUs have presented in this proceeding (summarized below) compiled for the most recent historical year and a forecast year are sufficient to identify TOU periods from the grid perspective.

- L4, Net Load for CAISO area;
- Distribution of net load for CAISO (box-and-whisker diagrams);
- Load and/or Net load by IOU service area by hour;
- Marginal Energy costs by hour;
- Marginal Generation Capacity costs by hour;
- Flexible capacity costs assigned to the end of the ramp period (or modifying marginal energy costs to account for potential ramping constraints); and
- Distribution system peak hours by circuit and substation.

c. 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?

TOU periods should be for typical days. As SDG&E stated in its April 29 comments, data should be developed on the frequency of days that are likely to experience over-generation and frequency of days likely to experience insufficient generation to establish super off-peak and super on-peak TOU periods respectively or, alternatively, dynamic rate options. In the case of over-generation, the analysis requires the level of MWs of must-take generation. The CAISO used 15,000 MWs in its analysis based on 2013 and 2014 analysis, which is reasonable for the recent historical years, but that assumption should be revisited in future updates based on forecasted changes in the generation mix (e.g., retirement of once-through cooling plants, changes in CHP, changes in long-term imported coal contracts, and potential SB 350 expansion of the CAISO footprint). A similar analysis of a super on-peak period that considers the frequency of days of system stress could also be included.

Data on customer engagement with and understanding of various TOU structures and customer persistence on the rate may be important for determining "tweaks" (minor adjustments) to the TOU periods, but should not have a major impact on the definition of TOU periods since the key to the design of TOU periods is aligning customer incentives with costs and system benefits associated with changing behavior. Examples of tweaks to the TOU periods for customer engagement and understanding would include changes in differentials for TOU rates or reducing the number of TOU periods over which rates are averaged for TOU periods to make TOU periods easier to respond to. Data from past rate designs and pilots, including the residential TOU pilot results, should be allowed to be used in utility rate proceedings for determining tweaks to TOU periods initially established based on grid needs.

Other data such as bill impact data for various customer classes and/or segments of customer classes, and customer understanding of relative prices should not impact the definition of the TOU period, but may ultimately impact rate design.

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)?

MGC provide the key information that can assist in determining TOU periods. MGCC have been allocated by any one of a number of methods, all of which will generate similar results. These approaches should be considered in the IOU's rate design proceedings, and not specified in this proceeding. The key is that the allocation should be forward-looking, since the time of day when there is a relative need for capacity is shifting to later in the day.

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.

TOU pricing should address "every day" cost differences. For that reason, SDG&E supports the use of MGC and the CAISO analysis that focuses on average net loads and also includes the distributions of the net loads based on the variations in load and variable renewable output. Net loads are highly correlated with energy prices, and average net load differences are related to typical differences in energy prices at various times of the day and week. In addition, use of average net loads highlights the ramping issues that are increasingly important. Moreover, the CAISO included data on the frequency of certain events, such as potential low or negative prices in its box-and-whisker diagrams. This type of data can separate frequent or "typical" events, which are appropriate for TOU pricing, from infrequent events that are better addressed via dynamic rates.

However, CAISO's methodology for the determination of TOU periods should not be used. First, the CAISO approach to determining the super off-peak period should be adjusted. Based on a data request response, "the CAISO used the median of the net load below 15,000 MW to determine the super off-peak period." SDG&E agrees with the CAISO method that TOU periods should be based on "typical days," so the use of the median is appropriate with variable renewables creating a distribution of days with different levels of net load. Analysis of 2014 CAISO data on net load from this proceeding and 2017 data from the Resource Adequacy proceeding show that currently and in the near future there are few days with at least one hour where net load is less than 15,000 MW. This type of analysis suggests that dynamic pricing (or hourly pricing if appropriate) is a better option to address the issue instead of establishing a TOU period. Analysis of 2021 CAISO data on net load from this proceeding, however, does show that

March and April weekdays have a number of days with hours where net load is less than 15,000 MW, justifying the CAISO proposal for a super off-peak period.

Table 1. Percentage of Days with at Least One Hour of Net Load Less Than 15,000 MW

	2014		2017		2021	
Month	weekday	weekend	weekday	weekend	weekday	weekend
Jan	0%	0%	0%	0%	5%	88%
Feb	0%	0%	0%	0%	19%	75%
Mar	0%	0%	0%	11%	55%	70%
Apr	0%	0%	0%	88%	36%	88%
May	0%	0%	0%	88%	5%	75%
Jun	0%	0%	0%	0%	0%	90%
Jul	0%	0%	0%	0%	5%	38%
Aug	0%	0%	0%	0%	0%	0%
Sep	0%	0%	0%	13%	0%	33%
Oct	0%	0%	0%	13%	0%	50%
Nov	0%	0%	0%	10%	19%	89%
Dec	4%	0%	4%	0%	5%	67%

The CAISO analysis depends on the minimum level of 15,000 MW, a value that was based on 2013 and 2014 CAISO experience. Specifically, it is based on the mix of must-take resources existing in 2013 and 2014, the hydro conditions in 2013 and 2014, as well as the export constraints existing in 2013 and 2014. The 15,000 MW may be an appropriate screen for near-term (i.e., 2015 – 2017), but additional analysis needs to be made of the 15,000 MW level before it is used in more distant forecast years. Does the retirement of older once-through cooling facilities change the 15,000 MW level? Do hydro conditions expected in the future impact the level? Does a changed amount of baseload combined heat-and-power facilities impact the level? Does the expiration of load-serving entity imported coal contracts impact the level? Does expansion of the CAISO footprint change the level? Accordingly, further analysis should be developed of the minimum level of generation used in the analysis of super off-peak periods.

Also, the choice of hours and months for the super-peak period should not be based solely on the amount of ramp, but also on (1) the highest net load hours of the year (i.e., the hours most likely to experience a shortage of capacity or hours of likely loss of load); and (2) the frequency of very high load events. This type of data can separate frequent or "typical" events, which are appropriate for TOU pricing, from infrequent events better addressed via dynamic rates.

To determine if there should be a super on-peak period, the analysis should also look at (1) the level of net load and (2) the frequency of very high net load days. With regard to the level of net load, it is not clear what the criterion would be for "high." Based on the CAISO data for 2021, the net load was highest in July through September, the only months with average net loads above 36,000 MWs and the only months with days that have peak net loads over 43,000 MW. In the loss of load expectation analysis for the State from E3's capacity planning model for 2021, the RECAP model, 4 p.m. to 9 p.m. in July through September contained 96% of the expected unserved energy, with September having a significant amount of expected unserved energy. As with the super off-peak, any determination of a super on-peak period should consider whether dynamic pricing combined with a summer on-peak period is preferable to a super on-peak period. A level of MW should be determined to be an appropriate stress level (e.g., 43,000 MW) and the number of days where the net load exceeds that level in a month should be considered in determining whether a TOU period or some form of dynamic rate is preferable.

MGC and additional utility-specific data described in question 1 above should also be considered in the design of the TOU periods in order to provide appropriate price signals. The data provided should be for the most recent historical year and a forecast year.

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?

See response to question 3 for the type of analysis the CPUC should provide. The CPUC should update historical net load data on an annual basis and forecast data on a biennial basis after it conducts a new forecast as part of the Long-term Procurement Plan/Integrated Resource Plan proceeding.

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.

Based on the data and methods described above, (1) the number of seasons defined for the purpose of setting TOU rates and (2) which months should be included in which seasons should be utility-specific based on MGC differences for the TOU periods (super off-peak, off-peak, on-peak, and super on-peak).

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?

The CAISO analysis with the modifications described in responses 1 and 3 is a reasonable starting point for determination of TOU periods. However, SDG&E disagrees with the specific TOU periods proposed by the CAISO. .

As described in responses 1 and 3, the super-peak period should consider not just the amount of ramp, but the level of net load and its relationship to the needs for peak capacity that would be part of MGCC. The CAISO does not address the potential use of dynamic pricing.

Also, the CAISO analysis of TOU periods does not suggest 4 seasons for rates as it has been interpreted by Energy Division.[9] The CAISO has been clear that it is not involved in developing rates. Each change in TOU periods does not necessitate a change in rates. For example, the CAISO TOU periods could be implemented with one "season," averaging all hours in a TOU period throughout the year (e.g., all hours in the super off-peak period throughout the year) if the MGCs were sufficiently similar for each of the defined periods.

And, as indicated previously, these periods could be somewhat modified by utility-specific data described in responses 1 and 3 and as described in the Other Considerations for Designing TOU Rates section of these comments.

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

No, the use of MGCs and CAISO method as modified by SDG&E in responses 1 and 3 are appropriate to identify periods of grid need to provide a TOU period definition and appropriate price signals based on grid need.

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?

SDG&E does not think TOD periods should be addressed in this proceeding. SDG&E changed its RPS TOD period summer definition beginning in 2005 and changed its on-peak and off-peak definitions to match Rate Design Window-proposed hours of on-peak and off-peak TOU periods in 2013 even though the Commission ultimately rejected SDG&E's proposal in D.15-08-040. For CHP contracts, the TOD periods are set through 2020 by the CHP Settlement approved in D.10-12-035 and cannot be changed. Dispatchable generation does not have TOD periods as they bid into the CAISO markets and so receive accurate price signals.

---

[9] Robert Levin, Comparison of Utility MGC* Data, May 5, 2016 presentation, slides 3-9.

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

Regardless of the TOU period definition, the high cost hours will continue to be the high cost hours. For TOU periods to be effective in aligning costs, TOU period definitions should provide a group of high cost hours in the on-peak period, low cost hours in the super-off peak, with mid-cost hours in the "mid-peak" period. TOU period definitions that follow this guidance will create price signals that provide customers information about the high cost periods and the low cost periods, and thereby incent economically efficient behaviors that reduce system costs *and* reduce customer bills when customers shift their energy usage to low cost time periods to avoid usage during high cost time periods. Under a TOU energy-only rate, a cost-based TOU differential results from the average price for marginal energy in the period and the occurrence of generation capacity need in the period. TOU period definitions that fail to follow this guidance will result in placing high cost hours in multiple periods, which once averaged, will result in muted TOU differentials and thereby fail to provide customers meaningful signals regarding their actual cost of service. Such customers will have little opportunity to save on their bills with changes in energy consumption.

To ensure that TOU periods are correctly defined, SDG&E supports the use of the Rate Design Principles (RDPs) from the Residential Rates Design OIR. Table 1 below presents the RDPs in the four categories consistent with D.15-07-001: cost of service, affordable electricity, conservation and customer acceptance.

Table 1: Rate Design Principles

Cost Of Service RDP	Affordable Electricity RDP	Conservation RDP	Customer Acceptance RDP
(2) Rates should be based on marginal cost; (3) Rates should be based on cost-causation principles; (7) Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals; (8) Incentives should be explicit and transparent; (9) Rates should encourage economically efficient decision-making.	(1) Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost.	(4) Rates should encourage conservation and energy efficiency; (5) Rates should encourage reduction of both coincident and non-coincident peak demand.	(6) Rates should be stable and understandable and provide customer choice; (10) Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

The question of whether TOU periods warrant change should begin with the question of whether such a change is justified by changes in cost of service. The RDPs also provide guidance for other considerations that will need to be included to determine if a proposed change should be approved and implemented.

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 law5 identified in this proceeding.

Absent legislative or regulatory guidance and requirements, the question of changing TOU periods should focus on changes in cost while still balancing the RDPs. Smaller incremental changes may be easier for customers to handle than large changes. While a preset timing, such as 5 years, may provide some benefit from greater predictability, preset timing may not work in this evolving industry climate. But focus should be on cost of service – otherwise stale TOU periods can shift costs between customers and increase system costs when customer incentives don't align with system needs.

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?

Grandfathering TOU periods should not be permitted. Grandfathering customers on TOU periods would exacerbate existing cost shift issues that justify the need for new TOU periods and will result in minimizing the value of changing TOU periods, since not every customer would be responding to the new, more accurate, TOU price signals. Grandfathering TOU periods could result in customers receiving conflicting price signals with some customers seeing a price signal to use less at the same time other customers see a price signal to use more. Even further, grandfathering TOU periods could result in a single customer (e.g., commercial customer with multiple accounts) receiving conflicting price signals with some accounts receiving a price signal to use more at the same time that customer's other accounts see a price signal to use less. In addition, multiple TOU periods will create additional challenges and customer confusion related to marketing and education.

While changing TOU periods too frequently can result in a situation where customers ignore price signals due to uncertainty, failure to address the need for TOU period change in a timely manner will simply allow the problem to persist—failure to align customer incentives with the costs drivers of the system, means high cost of service overall. Customer reaction will depend upon a variety of factors, including marketing and outreach as well as rate differentials.

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?

A menu of rate options should be available to all customers. However, this menu of options should be based on a single foundational set of TOU periods that are based on costs (i.e., all should identify the same high cost hours). The menu of options could consist of rate options that have differences in TOU price differentials, number of periods, and TOU rates with and without dynamic pricing.

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 periods should not be required to be the same across all CA IOUs for reasons discussed in response to question 1a. While general consistency is expected, there may be some IOU-specific differences. TOU periods should be the same in an IOU's service territory given that these costs occur at the system level.

Given the system level nature of commodity costs that drive the TOU period definition, the foundational TOU periods (when high cost hours occur) should be same, but individual IOU rates may have variations (e.g., number of TOU periods) as discussed above.

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?

In addition to pilots, providing customers with a menu of TOU options will be critical to ensure goals related to customer engagement are achieved. The availability of options, such as number of TOU periods, different TOU rate differentials, and TOU rates with/without dynamic pricing, will increase the probability that customers will find a TOU option that suits their needs. The success of a menu of options will require education and outreach regarding the various options (e.g., lower TOU rate differentials may reduce potential bill impacts but would also result in less opportunities to save for those who are able to shift usage).

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

TOU differentiation should be applied for the recovery of costs that vary based on TOU period. This would include all components of commodity services – including generation capacity costs which would be applied as an on-peak demand charge.

IV. CONCLUSION

SDG&E appreciates the opportunity to provide these comments and responses to the Scoping Memo questions. SDG&E also looks forward to continuing to work with the Commission on these important TOU issues.

Dated: June 27, 2016

San Diego Gas & Electric Company

/s/ John A. Pacheco

By: John A. Pacheco

Attorney for: SAN DIEGO GAS & ELECTRIC COMPANY
8330 Century Park Ct.
San Diego, CA 92123-1530
Telephone: (858) 654-1761
Facsimile: (619) 699-5027
E-mail: JPacheco@semprautilities.com