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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 (Filed December 17, 2015)

OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) IN RESPONSE TO QUESTIONS IN SCOPING RULING OF MAY 3, 2016

GAIL L. SLOCUM
CHRISTOPHER J. WARNER
RANDALL J. LITTENEKER

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-2179
Facsimile: (415) 973-0516
E-Mail: rjl9@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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I. INTRODUCTION

Pursuant to the May 3, 2016 Scoping Memo and Ruling of Assigned Commissioner Picker and Assigned Administrative Law Judge McKinney (Scoping Memo), PG&E provides its opening comments in this proceeding, including its responses to Questions (a) 1 – 8 and (b) 1 – 7 as set forth in the Scoping Memo.

PG&E generally agrees with the refined scope that focuses this proceeding solely on methodological principles, not on rate design or actually setting Time-of-Use (TOU) periods here, but rather providing broad guidance to be used in setting TOU periods in each of the three Investor Owned Utilities (IOU's) General Rate Cases (GRC) and/or Rate Design Window (RDW) proceedings. Great value has been gained through the exchange of information provided during the workshops held in this proceeding. PG&E includes as attachments to these comments the presentation materials it prepared for those workshops, which are discussed in response to some of the questions in the Scoping Memo.

PG&E sees two major outputs from this proceeding that would be useful to the CPUC's subsequent proceedings considering adjustments to TOU periods for each of the individual utilities in their future rate proceedings.

A. The CPUC Should Adopt High Level Guiding Principles in this Proceeding, Not Specific or Proscriptive Methodological Requirements

First, under the Scoping Memo's refined and narrowed approach and shortened schedule, and as discussed with the ALJ at the June 8, 2016 technical workshop, the CPUC should focus in its decision on establishing a limited number of high level guiding principles that would be used in the IOUs' future GRC and RDW proceedings to develop TOU periods, based upon the workshops and written information and comments filed by the CAISO, the IOUs and other parties participating here. PG&E's suggested list of these principles is set forth below. In an effort to make it possible to issue a final decision by the end of 2016, the Scoping Memo has foregone the possibility of holding evidentiary hearings, which would be necessary if the CPUC were to seek to resolve here the many factual issues involved with each utility's marginal generation cost methodologies and results. Thus, while an informal technical workshop was held on June 8, 2016, PG&E respectfully requests that the CPUC use the information gained there to develop high-level guiding principles, and not attempt to adopt a single, specific proscriptive methodology that all three IOUs would be required to use. This is important for the substantive reason that there are significant differences in circumstances among the IOUs. It is also important for the procedural reason that the parties have not been afforded the due process that would be necessary to develop an adequate record on these complex methodological issues. The Commission simply does not have the necessary robust and complete factual record here to do so.

Rather, by keeping this proceeding focused on developing broad guiding principles, the IOUs and other parties can take such guidelines into consideration as they develop their detailed factual showings in future GRC and RDW proceedings that consider adjustments to then-existing TOU periods. Thus, this decision should expressly provide the direction that specific methodological issues relating to the development of updated TOU periods will be addressed in the IOUs' individual GRC and/or RDW proceedings.

B. The CPUC Should Receive Into Evidence the Data and Analyses CAISO presented in this Proceeding, and Consider a CPUC existing Mechanism to Obtain Updated Data for All Parties to be able to Use.

Second, PG&E recognizes that a major reason this proceeding was established was to provide the CAISO with a "one-stop shop" for putting its data and analysis of systems operational considerations onto the record at the CPUC, in such a way that obviates the need for CAISO to provide a witness to appear in each and every IOU GRC Phase II or Rate Design Window proceeding considering TOU period updates. To achieve this objective, PG&E respectfully requests that the CPUC receive into evidence the CAISO's analysis filed on January 22, 2016 (based on 2013-2014 net load data with a 2021 forecast horizon) as well as the updated CAISO analysis submitted in May 2016 (based on updated data that included calendar year 2015 net loads), with the express recognition that its contents were never subjected to testing through formal cross-examination. The CAISO data and information provided will then be able to be cited to in other proceedings where utility-specific showings are considered, including parties' own analyses and recommended specific TOU period-related methodologies, as well as any available data on utility-specific customer preference considerations. While PG&E supports adoption of a mechanism to provide a vehicle for CAISO to file updates of its data and analyses, the CPUC's decision here should expressly recognize that the outcome on TOU Periods for any given future proceeding may differ somewhat from the CAISO's assessments relating to TOU period hour structure because of utility specific cost and other data, and additional analysis by the IOUs and intervenors that goes beyond the limited analysis provided by CAISO. This includes the foundational issue of the marginal cost basis for determining the high cost times of day that should be covered by the peak period, as well as secondary considerations such as analysis of customer preference considerations that might help refine selection of TOU periods for rate options, while staying close to cost-based results. PG&E suggests that the IEPR/LTPP process is likely to provide a good and generally-accepted source of updated data and assumptions that all IOUs can use going forward, while the exact vintage of IEPR/LTPP proceeding and set of assumptions used in each IOU's TOU-related proceeding will depend on the timing of such TOU-related proceedings and the uses to which such data and assumptions will be put.

C. PG&E's Proposed High-Level Principles

In Rate Design Windows or GRC Phase 2 proceedings in which the CPUC may re-set TOU periods, the IOUs, intervenors and the CPUC shall:

1. Consider the hourly (and where necessary, minute by minute) load and net load data filed by the CAISO at the CPUC (such as that submitted in this proceeding), and in future updates, as one input into developing TOU periods. For example, data regarding curtailment of RPS (Renewables Portfolio Standard) – eligible curtailment such as presented on slide 14 of the CAISO's February 27, 2016 presentation could also inform TOU periods, particularly the existence and timing of Super Off Peak periods, and would be important to update as RPS penetration increases.
    a. The CAISO and IOU presentations at the May 5, 2016 workshop resulted in overall consistent direction and fit and aligned with the shapes that the CAISO shows (i.e., the shape and the TOU periods are largely similar).
2. Use forward-looking data, forecasted over a period of at least 5 years into the future, so that the adopted TOU period will be stable, given that there are significant marketing, education and outreach costs inherent in adequately communicating with customers about a change to TOU periods.

3. Use Marginal Generation Cost data as the primary input for setting TOU periods in utility- specific GRCs and/or RDW proceedings, to ensure that peak periods cover the highest cost hours, in order to help reduce overall system costs and help bring rates down for all customers. In developing TOU periods for rates, it is key to use Marginal Generation Cost data so rates are cost-based.
4. Develop Marginal Generation Costs (MGCs), in utility-specific GRCs or similar proceedings, using an analysis of net load (as CAISO does) and adjusted net load (as PG&E does building off CAISO's net load analysis), in a way that reasonably and defensibly forecasts MGCs in each IOU's service territory. In this way, it will be possible to align load based approaches with MGC based approaches, and at the same time, achieve cost-based TOU periods.
5. IOUs and other parties may also consider, in future utility-specific proceedings, whether Marginal Distribution Cost data might also be useful in helping set or refine the appropriate hours covered in updated TOU periods. However, the CPUC also recognizes that there are IOU-specific differences such that consideration of Distribution data is not required and may not always be appropriate depending on the utility-specific circumstances.
6. Other considerations, such as evidence on customer preferences may also be considered in utility-specific proceedings in which TOU periods are being considered.
7. Customers' TOU periods should be adjusted as promptly as possible to reflect cost-based modifications, without grandfathering, so as to avoid costly individual "vintaging" and to maximize the overall cost reduction and rate reductions that are only possible through cost-based TOU periods.

8. PG&E notes that due to congestion and the different mix of resources in the three IOU territories (more hydro and now nuclear in the north, more solar in the south), prices at the three IOUs' DLAPs[1/] – and thus marginal energy costs to load – can differ. Setting TOU periods (and rates) separately for each IOU results in lower costs for each IOU and in total than would result if all three IOUs were forced to have the same TOU periods.
9. Because methodologies are evolving, and are expected to evolve over the next several years, quantitative approaches should be considered in individual proceedings; examples include how to quantify and apportion flexible capacity, allocating distribution costs, etc.
10. It is important to ensure flexibility in providing guidance for developing TOU periods because of the different IOU resource mixes, and because the market is expected to evolve over the next several years in response to, among other things, Energy Imbalance Market (EIM) proposals and the possibility of new Participating Transmission Owner(s) (PTO) being added to the CAISO.

PG&E Recommends Findings of Fact and Ordering Paragraphs include:

- The CPUC is taking official notice under Rule 13.9 of the Commission's Rules of Practice and Procedure of its sister agency, the CAISO's, January 22, 2016 Report entitled "CAISO Time-of-Use Periods Analysis" (based on 2013 – 2014 net load data) as well as the Updated CAISO analysis submitted in May 2016 (based on updated data that included calendar year 2015 net loads), and make it part of the CPUC's official record in this proceeding to which all parties can cite in future proceedings based on official notice and
- Parties should use historical data drawn from the CAISO's OASIS[2/] database, and analysis from the CAISO's Market Performance and Planning Forum reports, plus assumptions and forecasted data drawn

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1/ Default Load Aggregation Point. Costs to load are measured at these points in the CAISO market.

2/ Open Access Same-time Information System, accessible at http://oasis.caiso.com from the IEPR/LTPP/IRP processes, to inform their GRC and RDW proceedings. Each IOU and all intervenors may reference such CAISO reports and bring them into evidence in future GRC, RDW and other proceedings, under Rule 13.9, as an input for the CPUC to consider when deciding upon proposals for updated TOU periods.

- The CPUC will not evaluate TOD factors in this proceeding. These are already addressed in RPS annual filing and related proceedings, which allow IOUs to refer to more updated and often confidential market data. Because TOD factors must be set for the duration of a contract, typically 20 years, the interplay between the TOU periods and TOD factors is complex. Also, different parties may be interested in these supply-side issues who are not represented in this OIR proceeding.

II. RESPONSES TO SCOPING MEMO QUESTIONS

PG&E provides below its responses to the questions set forth in the Scoping Memo, keeping in mind the proposed guiding principles presented above.

A. Methodology for Setting TOU Periods

QUESTION a.1.

Please see the table below for text of the questions.

PG&E'S RESPONE TO QUESTION a.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. (*See* subquestions from Question a.1. set forth across the top row of the table below, with the left column listing the various bullet-pointed factual information the CPUC requests be addressed for each question. PG&E has used a table to organize its responses, so as to provide an easier to understand format for the convenience of the reader).

Answer a.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?
(a)(i) Hourly metered load, disaggregated by location, customer class.	PG&E's class kW sample of hourly customer load data that contain division and customer class information	PG&E recommends that this data be analyzed to determine summer partial peak period.	PG&E recommends using Table 1's "L2 Hourly Metered Load" approach. This approach is preferable because it represents the load on the distribution system. It is location-specific, by division[3] and can show how the hourly load pattern varies across the divisions. A suitable partial peak period that broadly covers the distribution peaks across the divisions can be determined using this data.	The data is currently available.	The data is currently available.

3/ PG&E uses data aggregated to its 19 Divisions.

(a)(ii) Net load, disaggregated by location, customer class.	Net load—as defined by both the CAISO and PG&E—is relevant but not by location and customer class.	Reports by CAISO as part of this proceeding (February 26, 2016 and May, 2016); and the OASIS web portal	PG&E recommends using Table 1's "L5—Adjusted Net Load (as proposed and used in the 2015 RDW by PG&E). Adjusted Net Load starts with the CAISO's net load, and also nets out nuclear and hydro. This approach is preferable, and better fits the data, because it isolates the share of load to be met by fossil generation, which is on the margin. (i.e. hydro and nuclear are not on the margin for PG&E).	The data is currently available.	The data is currently available.
(a)(iii) Usage data, disaggregated by location, customer class.	Same as (a) (i)	Same as (a) (i)	Same as (a) (i)	Same as (a) (i)	Same as (a) (i)
(b) Hourly wholesale supply data, disaggregated by location and type of generation.	Hourly wholesale supply data are relevant, disaggregated by type of generation. Disaggregation by location (DLAP) may or may not be relevant, depending on congestion and	Reports by CAISO as part of this proceeding (February 26, 2016 and May, 2016); and the OASIS web portal	Same as (a) (ii)	Same as (a) (ii)	Same as (a) (ii)

	other effects.				
(c) Estimated hourly load and supply for years through 2020.	Forecast hourly load and supply for years through 2020 are relevant.	Forecast hourly load and supply can come from the LTPP/IEPR.	Same as (a) (ii)	Same as (a) (ii)	Same as (a) (ii)
(d) Wholesale price data, by location and time, and estimates for the future.	Actual and forecast wholesale price data by location (DLAP) and time are relevant.	Actual wholesale price data comes from OASIS. Forecast wholesale price data can come from a number of different price models, e.g. PG&E's public model, PLEXOS or other methods. Aggregate price forecasts (e.g. monthly averages) could also be useful; available on ICE or from IEA.	N.A.	The data is currently available.	The data is currently available.
(e) MGC hourly forecasts.	Marginal Generation Cost hourly forecasts are relevant.	Such forecasts come from PG&E's public MGC model in the 2015 RDW and 2017 GRC Phase 2 proceedings. Other approaches could also be relevant, see 1(d).	N.A.	The data is currently available.	The data is currently available.
(f) Bill impact data for various customer classes and segments of customer classes.	Bill impact data can be relevant to determining transition approaches to new rate	Customer interval usage data.	N.A.	The data is currently available.	The data is currently available.

	structures including transition periods and customer education and outreach.				
(g)(i) Data on customer engagement with and understanding of various TOU structures.	Customer preference data can provide secondary input to help refine cost-based rate design, especially for optional TOU rates where customer acceptance is necessary to successful adoption of the new optional rate.	Utility-specific customer surveys, where available	N.A.	The data is currently available.	The data is currently available.
(g)(ii) Customer understanding of key rate features (TOU periods, relative prices).	Customer preference data can help determine the relative complexity of different cost-based rate design options.	Utility-specific customer surveys, where available	N.A.	The data is currently available.	The data is currently available.
(g)(iii) Customer persistence on the rate, customer acceptance based on different segments of customer class.	Customer preference data can help distinguish differences by customer segment in ability to understand different cost-based rate design options.	Utility-specific customer surveys, where available	N.A.	The data is currently available.	The data is currently available.
(g)(iv) Effect of technology on customer acceptance of and engagement with TOU rates.	Is not relevant for determining TOU periods.		N.A.		

(g)(v) Effect of automation on TOU goals of load shifting and customer satisfaction.	Is not relevant for determining TOU periods.		N.A.		
(g)(vi) Effect of technology and automation on customer acceptance and load shifting response to complex TOU rates.	More information may be available in the future that could be addressed in future rate cases.		N.A.		
(h) 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?	Customers' hourly metered load data	Class KW sample data available from PG&E	This data has limited use since distribution load is location and utility specific, and should be used to supplement the system level generation marginal cost which is the primary determinant of TOU periods. Use of this data and methodology should be out of scope from TOU OIR and subject of other utility specific proceeding such as General Rate Case (GRC) Phase 2.	The data is currently available	The data is currently available.
(i) Distribution system peak hours by circuit and/or by substation.	This data is not relevant for determining TOU periods	N/A	N/A	N/A	N/A

	designed to apply for the entire PG&E service territory.				
(j) Other measurements to identify hours that are operationally challenging for the system.	Anything that will identify hours that are operationally challenging for the system is relevant. PG&E considers ramping and curtailment data to be particularly important (please see slides 10 and 11 in PG&E's presentation at the May 5 2016 TOU OIR workshop, provided in Attachment B.)[4]	CAISO's ramping data by generation type and hour; or computed from net load data described above	Ramping data computed from net load or adjusted net load can be studied to identify potential adjustments necessary to the TOU periods based on Generation Marginal Costs (MGC). Ideally MGCs would already reflect operational challenges.	Data on curtailment (by hour and technology type) is not currently available except as summaries in annual or quarterly CAISO reports.	CAISO could provide hourly data on curtailment by technology as an extension of the Renewables Watch data set.
(k) Forecast changes to market prices and load shapes under an expanded CAISO market.	Forecast changes to market prices and load shapes (net and adjusted net) under an expanded CAISO market are relevant.	Studies from LTPP/IEPR process	Adjusted Net Load shapes (since most related to prices), and prices themselves	LTPP process and other studies by CAISO and IOUs	See left
(l) Greenhouse gas emissions intensity associated with changing load shapes.	While greenhouse gas emissions intensity is associated with changing load shapes, it is not necessary to separately take GHGs into account because the price of carbon is	The price of carbon is embedded in gas prices—both actual and forecast. Thus, to the extent fossil fuel use changes with changing load shapes, the market heat	Values come from the IEPR Production Cost Model Input Assumptions	Publicly available forecasts of GHG emission prices are limited	TBD

4/ PG&E's presentation is titled, "*Marginal Generation Cost – PG&E's Methodology*" and is provided in Attachment B.

	embedded in natural gas prices that are already reflected in the MGC forecast.	rate will change. Market heat rate—i.e., electricity price divided by natural gas price—will change. Market heat rate is a surrogate for greenhouse gas emissions intensity. The results of past cap and trade auctions are publicly available from the Air Resources Board. Forecast floor prices are also publicly available.			

QUESTION a.2.

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

PG&E's RESPONSE TO QUESTION a.2.

(i) Yes, marginal generation capacity costs developed in IOU GRCs (when added to marginal energy costs) are an appropriate basis on which to set TOU periods.

(ii) Marginal generation capacity costs should be allocated to time periods in one of two ways: (a) Either on the basis of the top 100 to 250 hours, or using a similar approach like PG&E's Peak Capacity Allocation Factor, or PCAF, methodology where the number of top hours is not specifically prescribed in advance, as described in PG&E's May 5, 2016 presentation[5/]; or (b) Using a Loss of Load Expectation (LOLE) model such as E3's publicly available RECAP model. Either of these two methods is appropriate to use, as both arrive at virtually identical TOU period results.

(iii) If the PCAF method is used, then allocate MGCC by Adjusted Net Load for best results.

(iv) MGC data are generated from many inputs—e.g., natural gas prices, electricity prices, generator cost and operating characteristics, discount rates, etc.—each getting stale at different rates. MGC data are currently developed for each IOU's GRC Phase 2 proceeding approximately every three years. This is an appropriate time period.

QUESTION a.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.

PG&E'S RESPONSE TO QUESTION a.3.

PG&E uses Generation Marginal Costs (MGCs), forecast at hourly level for a target year, as the primary input for determining TOU periods. The forecast is developed using a statistical model that uses Adjusted Net Load (ANL) as the driver of Effective Market Heat Rate and Marginal Energy Cost, and an hourly allocation of Marginal Generation Capacity Cost to the top hours of ANL based on the PCAF methodology. ANL is calculated by subtracting nuclear and hydro generation from the CAISO's Net Load.

5/ *Please See* PG&E's presentation from the February 26, 2016 CPUC Workshop titled, "*What Factors Should Affect Selection of Time-of-Use (TOU) Periods?"(Slides 10—12); the presentation is contained in Attachment A.*

The first step is to determine the seasons. Using the hourly MGCs, the summer and winter seasons are determined. The distribution of the highest 100 and 250 marginal generation cost hours across the months is used to determine the summer months that best capture most of the highest MGC hours. Based on this approach, CPUC adopted a four-month summer season in PG&E's 2015 RDW.

Once the seasons are determined, the next step is to determine the season-specific TOU hours based on how Top 100 and 250 MGC hours are distributed across hours of the day. Based on this distribution, PG&E designs various TOU period scenarios to perform detailed analysis. (For example, one would compare a 5:00 pm – 10:00 pm period versus a 4:00 pm – 9:00 pm for weekdays only or all days of week). PG&E uses two metrics: (1) Percent Highest Cost Hours Captured, and (2) False Positive Rate, to measure how efficiently a TOU period scenario captures the highest cost hours while avoiding the non-highest cost hours. This easy-to-understand approach (ironically known as a "confusion matrix") is standard, and is widely used to describe the performance of a classification model (or "classifier"). Here we are attempting to classify the highest cost hours as the TOU peak period.

PG&E prefers to determine the super off-peak period based on the distribution of the hours with negative or very low MGC. However, a separate season for super off-peak period may not be necessary. The rate design becomes simpler and easier to implement if, instead, the super off-peak is implemented as a "subtractor" applicable during certain hours on a winter (or even summer) rate.

PG&E believes that TOU periods should be valid for a significant period of time (at least five years). Hence, the data should be updated once in every GRC Phase 2 filing, but not necessarily result in a change in TOU periods every filing.

QUESTION a.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?

PG&E'S RESPONSE TO QUESTION a.4.

(i) 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?

In determining TOU periods, the greatest weight should be given to forecasted MGCs, and to a certain extent customer considerations such as ease of understanding and acceptance (especially with optional rates). Grid-related issues can also be considered to the extent they are not already captured in the MGCs, but they need to be quantified where possible so as to allow appropriate tradeoffs with marginal costs. For example, concerns about ramping capability may be sufficiently captured in MEC or MGCC forecasts; to the extent they are not, the impacts should be quantified (e.g., 3-hr ramp between 12,000 and 13,000MW imposes costs of $1,000 per hour on the system; 3-hr ramp over 16,000MW could lead to grid instability and has a very high cost).

(ii) What data should be obtained from CAISO to determine these periods?

Data such as the minute-by-minute load and generation data already provided as part of this proceeding is useful to give a solid grounding to the models used to develop MCG forecasts. Additional data such as extent and generation source subject to curtailment would also be useful; these data do not appear to be available on OASIS. Finally, going forward CAISO and others should provide analyses on how expansion of the CAISO footprint (and relaxation of contractual limitations) are likely to affect marginal costs.

(iii) How often should this data be updated?

Annually, perhaps as part of existing analyses provided by CAISO such as provided at the May 17, 2016 Market Performance and Planning Forum. Much of the data are updated on OASIS daily; if data regarding curtailment were updated daily as well, it would give greater situational awareness to planners, and potentially allow less stale data to be used in GRCs and RDWs.

(iv) What data is feasible for the CAISO to provide?

(See above in Section iii.)

QUESTION a.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.

PG&E'S RESPONSE TO QUESTION a.5.

PG&E recommends keeping two seasons, summer and winter as currently is the case. PG&E recognizes that one way to provide a super-off-peak credit to encourage higher usage during the potentially negative price hours would be to define an additional season, such as spring. However, PG&E finds it is preferable to provide the super-off-peak credit as an overlay to the TOU rate designed with just summer and winter periods, and not create a separate spring season. This would retain flexibility regarding the months to which the super-off-peak credits should apply. While negative price hours are expected to occur frequently during the months of March, April and May by 2020, it is possible that negative prices will also occur during other months with less frequency. As the penetration of solar generation (both behind the meter and utility-scale) increases, the regular occurrence of negative or very low MGCs will spread from weekends in March through May (as of 2016), to all days in March through May and weekends in some winter and fall months (as of 2020-2024, as shown in the CAISO's showing of February 26, 2016). Hence, applying a super off-peak credit that can slowly spread from the spring to other months, and a combination of static and dynamic super off-peak credit programs can provide a more appropriate, flexible approach.

QUESTION a.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?

PG&E'S RESPONSE TO Question a.6.

(i) Is the CAISO report reasonable?

The CAISO report shows both historical and forecasted net loads for the three IOUs, and develops a candidate set of TOU periods as of 2021. PG&E finds the use of net load alone (with no explicit consideration of cost, or of other cost drivers such as hydro and nuclear generation or ramp rate) unreasonable in that it does not adhere to the CPUC's principle of cost-based rates. However, PG&E does agree with many of the conclusions in the CAISO's report, including the general pattern (though not necessarily the specific hours) of peak and off-peak periods shown in that report.

CAISO's TOU period methodology relies on Net Load as a proxy of Marginal Generation Costs (MGCs), without taking into consideration the impact of hydro and nuclear generation on the Marginal Energy Costs (MECs). PG&E believes that TOU periods need to be cost-based, to achieve cost-based rate design which is the most important foundational rate design policy principle set out by CPUC. Net Load, while a proxy for Marginal Energy Cost, is often not the best predictor of it. Hence, PG&E has developed a statistical model that predicts MEC using Adjusted Net Load, which is a better proxy of MGCs, as described in PG&E's presentation at the May 5 2016 TOU OIR workshop, provided in Attachment B. The statistical model also includes other important adjustments, such as the effect of gas prices, ramping and curtailment.

While CAISO's methodology is not directly cost based, the resulting TOU periods determined by CAISO based on Net Load data are close to the TOU periods that PG&E developed using the MGC forecast based on Adjusted Net Loads. The important difference is that PG&E's forecast uses CAISO data, but applies a cost- based methodology to determine the TOU periods in order to achieve cost-based rate design.

(ii) Are CAISO TOU periods reasonable?

PG&E finds the CAISO's proposed TOU periods reasonable but not necessarily optimal, in that for some IOUs and some classes of customers they may represent a good balance between ideal cost-based periods and simplicity for customers, and for others they may not.[6/] However, even considering a snapshot in time of 2021, different IOUs may have different patterns of MGCs that warrant different TOU periods (e.g., high costs in September, thus a longer inner summer period, or a later peak due to geographical differences).

PG&E notes that due to congestion and the different mix of resources in the three IOU territories (more hydro and now nuclear in the north, more solar in the south), prices at the three IOU's DLAPs – and thus marginal energy costs to load – can differ. To quote an example that was described during the June 8, 2016 technical workshop, if prices during the spring were very low in PG&E's service territory due to hydro production but moderate in the other service territories, then PG&E's rates should be lower in the spring (and a super off peak period defined to implement those rates) so that load in PG&E's service territory is incented to shift into the super off-peak times. To the extent that load indeed increases in PG&E's territory (but does not in the others, due to more moderate costs), congestion would be reduced which would lead to more economically optimum dispatch in both service territories.

(iii) Do we reach different conclusions?

PG&E lists below the key questions and the CAISO's conclusions on them that

6/ For example, PG&E's Opt-In TOU Pilot is now testing with residential customers a complex rate in comparison with simpler two-season rates. So, while PG&E is proposing a spring super-off-peak credit for non-residential customers, PG&E does not believe CAISO's complex TOU period with such a super-off-peak is something that should be automatically be assumed appropriate for the residential class.

CAISO reaches in its report. PG&E's response to each question is listed after CAISO's conclusion.

1. Does the time of the CAISO's coincident peak demand vary by season?
    a. CAISO Conclusion: Yes.
    b. PG&E Conclusion: Yes.
2. Does the time of the CAISO's coincident peak coincide with the IOUs' peak demand?
    a. CAISO Conclusion: Yes except for summer, the CAISO shows that PG&E is an hour later.[7]
    b. PG&E Conclusion: Yes for winter and spring, no for summer and fall; PG&E's peak demand occurs one hour later than the CAISO's, as shown in slide 4 in the CAISO's February 26 presentation and as shown in slide 2 of the CAISO's May 5, 2016 presentation.[8]
3. Is there a noticeable difference between weekdays and weekends/holidays?
    a. CAISO Conclusion: Yes.
    b. PG&E Conclusion: Yes, but customer considerations of simplicity may argue for using the same TOU periods for both weekends and weekdays.
4. Is there a need for IOU-specific TOU time periods?
    a. CAISO Conclusion: No.
    b. PG&E Conclusion: Maybe (*see* answer to (2) above). For example, PG&E's current data shows a 5pm-10pm peak by 2020, no longer a 4pm-9pm peak. This is consistent with CAISO's statement that PG&E's peak is an hour later than SCE's and SDG&E's. Similarly, September in southern California may be an inner summer month, in contrast to the CAISO's suggestion that only July and August be defined as inner summer months.
5. Should all three IOUs establish common TOU time periods based on the CAISO's needs?

7/ *See,* CAISO's workshop presentation in this docket titled, "CAISO's proposed TOU periods to address grid needs with high numbers of renewables", Slide 4, February 26, 2016.

8/ *See,* CAISO's workshop presentation in this docket titled, "CAISO's proposed TOU periods to address grid needs with high numbers of renewables", Slide 2, May 5, 2016.

a. CAISO Conclusion: Yes.
b. PG&E Conclusion: Not necessarily, as doing so may conflict with cost-based rate setting (*see* answer to (2) above, and answer immediately above).

6. Should TOU time periods be grouped by months?

a. CAISO Conclusion: Yes.
b. PG&E Conclusion: Yes, this helps reduce consumer confusion.

QUESTION.a.7.

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

PG&E'S RESPONE TO QUESTION a.7.

No, alternate methodologies are not necessary beyond those described above.

QUESTION a.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?

PG&E'S RESPONSE TO QUESTION a.8

PG&E's position is that TOD factors should not be part of this proceeding but should be evaluated in the RPS proceeding (*see* PG&E's initial comments in this proceeding).

First, PG&E would like to clarify the difference between "TOD periods" and "TOD factors." The former are time periods used for utilities' resource evaluation and energy resource contract payments, and the latter are energy payment allocation factors applied to generation provided during certain TOD periods. TOD factors and TOD periods may be related to the TOU periods, but there is no reason to expect or require them to be identical.

Second, although conceptually both TOU periods used for customer rates and TOD periods used to pay resources should reflect hourly and seasonal time differences in energy and capacity value, the actual periods and factors appropriate for each may differ due to the timing of when those TOD factors and periods are set, the duration of the Purchase Power Agreement (PPA), the need to fix the TOD period at a point in time, and changes in energy and capacity values. The interplay between the new TOU periods, on the one hand, and the TOD factors and periods used for new PPAs, on the other, is complicated. This is because the TOD factors and periods these contracts use generally look at 20-year time horizons and trends—consistent with the long-term nature of those contracts—whereas the CAISO's TOU period analysis and those used by the IOUs in GRC and RDW proceedings have shorter forecast horizons. Thus, it may be appropriate to use a longer-term forecast of hourly energy and capacity values than might be appropriate for rate design purposes.

Moreover, TOD factors and periods used for compensating generators are set prior to PPA execution. Any change to TOD factors and periods once PPAs are executed is akin to changing the agreed-upon PPA price. Thus, TOD periods may differ from TOU periods simply due to the timing of when the periods are adopted. However, because PPAs are signed and project investments are made after TOD factors have been set for that PPA project, the CPUC can change TOD factors in subsequent years that would only apply on a going forward basis to new PPAs without affecting prior contracts.

TOD factors represent the relative value of energy during different time periods. They will be higher during peak times when market prices are higher, and lower during "reverse demand" time periods when market prices are lower. PG&E's belief that TOD factors should not be addressed in this proceeding and that TOD periods for PPA payments may differ from TOU periods for ratemaking is not dependent on whether energy prices are high or whether excess generation is expected.

B. Other Considerations for Designing TOU Rates

QUESTION b.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.4.

PG&E'S RESPONSE TO QUESTION b.1

The primary principle the Commission should use is to set TOU periods that are as cost-based as possible. In other words, TOU periods should be defined so that the peak period includes a high percentage of high-cost hours and a low percentage of hours that are not high-cost.[9/] A method for doing this is described in PG&E's 2015 Rate Design Window testimony[10/] (also this method is summarized earlier in the response to Question a.3) and involves looking at various candidate TOU period definitions and selecting the one that best minimizes both "Type 1" errors (where high-cost hours do not get captured within the defined peak period hours) and "Type 2" errors (where low-cost hours do get captured). While the determination of appropriate peak period hours should primarily be based on empirical evidence (i.e., based on hourly forecasts of costs), it may be appropriate to exercise some degree of judgement to capture considerations of customer understanding and acceptance –and, as described above, perhaps also ramping – although these modifications should not result in the ultimate TOU period definitions straying very far from what is dictated by cost of service principles.

As a secondary matter, these cost-based results could be slightly refined using such considerations as ramping and customer preferences, but the TOU periods should still be generally aligned with costs.

QUESTION b.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

9/ Similarly, the off-peak period should be defined to include a high percentage of low-cost hours and a low percentage of hours that are not low-cost hours.

10/ See this testimony appended to PG&E's filing containing Supplemental information dated April 29, 2016 in this docket titled, "Pacific Gas and Electric Company's (PG&E) Response to Administrative Law Judge's Ruling dated March 17, 2016, Directing PG&E to file Supplemental Information.

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

PG&E'S RESPONSE TO QUESTION b.2

In the Residential Rate Reform OIR, the Commission determined that new TOU period definitions should remain in place for a minimum of five years.[11] PG&E agrees with this conclusion. Educating customers about changed TOU periods is a large and expensive undertaking, and customers also want stability so they can effectively respond to the new peak period hours (either by changing behavior or business operations, or investing in technologies to assist in doing so). Please see response to Question b.3 regarding added complexity that would result from grandfathering TOU periods. The previous TOU period definitions were in place for decades, and forecasts of future patterns of hourly costs suggest that the new, later in the day, peak period definition may similarly reflect cost patterns for many more than five years into the future.[12] But five years is the minimum period for which the new periods should remain in place, at which time they can be re-evaluated in light of the then-existing data on hourly cost patterns.[13]

PG&E believes the setting of TOU period definitions, and the re-evaluation of those periods five years hence, should both be done in utility-specific proceedings, either in GRC Phase 2 or Rate Design Window proceedings, based on utility-specific cost data.

QUESTION b.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?

11/ See D.15-07-001, p. 80.

12/ As described above in response to Question a.5, super off-peak periods are more likely to change as the amount of solar generation in the CAISO increases.

13/ While unlikely, if some unexpected change to cost patterns occurs less than five years from now that necessitates a re-examination of the TOU periods, parties could file applications for the TOU period definitions to be re-evaluated.

PG&E'S RESPONSE TO QUESTION b.3.

If, five years or more into the future, changing cost patterns necessitate a change to the TOU period definitions, the new definition should apply to all customers with no grandfathering permitted for two key reasons.

First, the main purpose of TOU periods is to provide customers with accurate, cost-based, price signals, so that they can adjust their hourly usage patterns accordingly. This purpose would be largely defeated if customers were allowed to remain on obsolete TOU rates whose peak period definition no longer reflects a changed cost pattern. For example, the current TOU period definitions for PG&E's non-residential customers include a peak period during weekday hours between Noon and 6 p.m. Up until several years ago, the Noon to 6 p.m. hours did indeed capture the highest-cost hours. However, more recently (and as will continue into the near future, at minimum), the high-cost 5-hour period is 5 p.m.-10 p.m. and the very highest-cost 3-hour period on the PG&E system is occurring from 6 p.m. to 9 p.m. So the current TOU rates provide a perverse incentive for grandfathered customers to shift usage to the highest cost 6p.m. to 9p.m. period, rather than to the lower cost noon to 6p.m. period.

Second, maintaining multiple sets of TOU time periods for different groups of individual customers (i.e. vintaging) would be operationally expensive and confusing for customers. For example, if there were grandfathering of TOU time periods such that each customer would have the same TOU time periods for a minimum of five years, in year one there would be groups of customers on five different timetables for transition to the new time periods. Not only would managing a transition based on "vintaging" be complex and expensive, it would also be confusing for customers with multiple service agreements, as they would potentially have two different TOU time periods to consider in the management of their operations. Education and outreach would need to be more complex and costly in order to keep customers informed about the wide range of possible hourly prices of their various vintaged rate plans.

QUESTION b.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?

PG&E'S RESPONSE TO QUESTION b.4.

Since the time pattern of costs is independent of a customer's class or rate schedule, theoretically the TOU period definitions for every rate schedule should be the same, matching the time pattern of costs. Nevertheless, there are reasons that some slight variations between the TOU period definitions might be warranted for different classes:

i) Large Commercial Customers. It may be appropriate for larger, more sophisticated, customers to be on rate schedules with more TOU periods (for example, a partial-peak period and/or a super-off-peak period) than are applicable to smaller customers (who might see simple TOU period designs with just peak and off-peak periods). Default TOU periods within a class should be uniform to minimize customer confusion. For example, many large commercial customers have a large number of service agreements on different rate schedules. Inconsistent TOU periods among rate schedules could be confusing and costly for customers with multiple accounts and centrally managed operations, requiring more complex energy management planning.

ii) Agricultural Customers. Another place where a menu of TOU options may be important to offer is for agricultural customers. There are a variety of different types of agricultural operations with different needs and system constraints. It may be worth considering a small number of TOU options that could accommodate those differing needs (e.g. not just a 5-hour peak from 5pm to 10pm but also a 3-hour peak from 6 pm to 9 pm, if more manageable for some).

iii) Residential Customers. In addition, it may be appropriate to offer residential customers, for whom TOU rates are optional, a menu of TOU period choices. For example, customers could be offered the choice between (a) a TOU rate with only volumetric rates or (b) a more cost-based rate with either a fixed charge or a demand charge (or both), coupled with lower volumetric rates.[14/] As another example, residential customers might be offered a choice between TOU rates with slightly different peak period definitions. Specifically, if the peak period is determined to last for five hours between 4 p.m. and 9 p.m., customers might be permitted to choose between three TOU options with shorter, three-hour, peaks defined as (a) 4 p.m. to 7 p.m., (b) 5 p.m. to 8 p.m., and (c) 6 p.m. to 9 p.m. By limiting the length of the peak period, more customers would likely choose a TOU rate, and by managing enrollment on each of these three options, the utility could still, in the aggregate, achieve load shifting out of the high-cost 4 p.m. to 9 p.m. hours.

As long as, on a portfolio-wide basis, the signal to shift away from high-cost hours is being given, there can be variations as part of the menu of options, as long as all options generally align the peak period with the high-cost hours.

QUESTION b.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?

PG&E'S RESPONSE TO QUESTION b.5.

In general, since cost patterns can be different for different utility service areas, the TOU periods should be set separately for each utility in utility-specific proceedings. In particular, the information provided by the CAISO in this proceeding has already demonstrated that PG&E's net loads peak an hour later in the day, compared to those of the other two utilities, in the summer and fall. Consequently, PG&E's TOU period definitions should be based solely on the hourly pattern of costs in PG&E's service area. It makes no sense for PG&E's customers to be charged rates based on TOU period definitions that are reflective of costs in other parts of the state.

14/ See, SDG&E TOU Pilot AL 2835-E, and CPUC Resolution E-4769.

PG&E does not support different TOU periods for different local geographical areas. This is consistent with decades of Commission ratemaking policy, where rates have been approved that, while varying by customer class, are uniform across PG&E's service area. Moreover, if TOU period definitions are based primarily on hourly patterns of generation costs, which vary little with the customer's location, there is little justification for geographically-differentiated rates. Even if distribution costs are considered, it is not at all clear that this policy should be changed. In many local areas, loads peak at levels where they can be met by existing distribution capacity, so there is no need for a peak price signal to induce load shifting. In the relatively small number of areas in the system where peak loads are projected to be at risk of exceeding available distribution capacity, generally the annual number of hours where that situation exists outside of the proposed TOU period is relatively small, suggesting that a locally-dispatched peak day pricing program might be a better solution than TOU rates.

In addition, imposing different peak periods geographically could be confusing and costly for customers with multiple accounts and centrally managed operations, requiring more complex energy management planning. From a utility operations perspective, each additional geographically differentiated rate increases the costs of maintaining the rates in the billing system, training customer-facing support staff, and performing rates education and outreach.

With regard to the question of whether TOU rate periods should differ by customer class or segment, please see the response to Question b.4, above.

QUESTION b.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?

PG&E'S RESPONSE TO QUESTION b.6.

PG&E has employed customer surveys to collect data on customer preferences for different rate structure attributes.[15] However, PG&E does not consider customer preference data in rate design until after the initial data on marginal generation (energy and capacity) costs is available. Actual rate levels should be set to reflect costs to the greatest degree feasible, so as to (a) provide accurate price signals and (b) incent appropriate levels of load shifting based on the actual cost savings that will be achieved. As noted in PG&E's 2015 RDW proceeding, and again in Joint IOU comments filed in this proceeding on January 15, 2016,[16] while the primary and foundational inputs for designing peak periods are data on the hours with high forecasted marginal generation (energy and capacity) costs, the refinements to determine the final design of rates can involve a secondary consideration of customer preference data.

It is also important to distinguish that customer acceptance and engagement depends on more than the complexity of the rate structure and that not all attributes of a rate structure contribute to complexity. A rate structure is not necessarily more "complex" and difficult to understand for customers if it has a higher price ratio or longer peak period. These attributes of the rate design can influence customer acceptance but are not primary drivers of customer understanding. Other attributes of the rate structure, though, such as the number of time of use periods, days of the week, and seasons with peak period hours, can add complexity to the rate structure. Customer preference data helps determine the combination of rate structure attributes that will be acceptable to different customer segments. For example, in PG&E's 2015 RDW application proposing a 4pm to 9 pm peak period for an optional residential TOU rate (E-TOU), customer preference data showed that, when asked about peak period length in isolation,

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15/ *See* A.14-11-014, Exhibit PGE-1, Attachment A titled, "TOU Rate Development Conjoint Research Report. *See also* reference in PG&E's Phase 1 Opening testimony in R.12-06-013, page 2-57, footnote 68.

16/ *See* Joint Comments of San Diego Gas and Electric Company, Pacific Gas and Electric Company, and Southern California Edison Company on Preliminary Scope and Schedule of Initial Activities in Rulemaking 15-12-012 p. 7.

customers preferred shorter peak periods. However, when the peak to off-peak price ratio was factored in to the survey question as part of a conjoint analysis, customers were willing to trade off the shorter peak period for a longer peak period and, in this study, lower peak to off-peak ratio. Price ratio was the strongest driver of residential customer preference, in this study, even though a higher or lower price ratio did not necessarily affect the complexity of the residential TOU rate.

In both of these ways, customer preference data helped determine which of two cost-based rate configurations would likely be more acceptable to residential customers.

In particular, even though PG&E's data showed that the 9 pm-10 pm hour was a high cost hour, PG&E used customer survey data to decide to keep to a 4 pm-9 pm 5-hour period because customers preferred a 5-hour peak to a 6-hour peak.

QUESTION b.7

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

PG&E'S RESPONSE TO QUESTION b.7.

Cost-based TOU rates would not collect fixed costs in variable energy charges. Rather, fixed costs should be collected in fixed monthly charges. PG&E's proposed method for determining TOU period definitions is based on hourly patterns of both marginal (i.e., variable) generation capacity costs and marginal energy costs combined, and the peak rates should likewise reflect both.

III. CONCLUSION

PG&E believes that the adoption of the above-referenced high-level principles, the receipt of CAISO's analysis into evidence, and a mechanism for use of CAISO data in the future provides meaningful guidance to inform and empower the IOUs, intervenors, and the CPUC to make better decisions in future GRCs and RDWs in which TOU periods will be considered in the future.

PG&E has provided these draft high level principles to allow other parties to address and build on them in their reply comments. As with the Residential Rate OIR proceeding, in which the CPUC set forth a proposed list of ten rate design principles to guide that proceeding and provided all parties the opportunity to comment on them before they were adopted, PG&E looks forward to receiving the Proposed Decision in this proceeding so that PG&E and others may comment on the CPUC's own version of these high level guiding principles prior to their adoption in the final decision.

Respectfully submitted,

RANDALL J. LITTENEKER

By: *<u>/s/Randall J. Litteneker</u>*
RANDALL J. LITTENEKER

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-2179
Facsimile: (415) 973-0516
E-Mail: rjl9@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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