BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Continued Implementation of the Public Utility Regulatory Policies Act and Related Matters.	FILED PUBLIC UTILITIES COMMISSION JULY 26, 2018 SAN FRANCISCO, CALIFORNIA RULEMAKING 18-07-017

ORDER INSTITUTING RULEMAKING REGARDING CONTINUED IMPLEMENTATION OF THE PUBLIC UTILITY REGULATORY POLICIES ACT AND RELATED MATTERS

Summary

We issue this Order Instituting Rulemaking (Rulemaking) to consider changes to the State of California's existing implementation of the federal Public Utility Regulatory Policies Act of 1978 (PURPA)[1] for the state's investor-owned electric utilities. This Rulemaking will consider adoption of a new standard offer contract (SOC) that will be available to any Qualifying Facility (QF) of 20 megawatts (MW) or less seeking to sell electricity to a Commission-jurisdictional utility pursuant to PURPA (New QF SOC). This Rulemaking will also consider adoption of a price to be paid at the time of delivery where a QF has opted to sell as-available energy to the utility without a contract.

For the New QF SOC, we propose to start with the non-price terms provided in the QF SOC set forth as Exhibit 6 to Attachment A of Decision (D.) 10-12-035. This contract - known as the "Standard Contract for QFs 20 MW or Less" - was developed as part of the QF settlement approved in D.10-12-035 (QF Settlement), and will remain unchanged and available to QFs of 20 MW or less pursuant to the QF Settlement terms.

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[1] PURPA is codified generally at 16 U.S.C. §§ 824a-3 and 2601. Various provisions appear elsewhere in the United States Code. The federal regulations implementing PURPA are available at 18 C.F.R. Subchapter K starting at Part 290.

We anticipate that the New QF SOC resulting from this Rulemaking will primarily differ from the Standard Contract for QFs 20 MW or Less in that it will provide four alternative avoided cost pricing options for QFs, as required by federal regulations.[2] This Rulemaking will also consider whether the New QF SOC should wholly adopt the other terms of the Standard Contract for QFs 20 MW or Less, or whether any of those terms should be modified in the New QF SOC to ensure continued implementation of PURPA consistent with federal and state laws and regulations.

This Rulemaking is not intended to change or interfere in any manner with existing PURPA contracts between California investor-owned utilities and QFs, with any currently available PURPA contracts, with any existing PURPA program, or with any aspect of the QF Settlement approved in D.10-12-035.

1. Background and Procedural History

The Commission has a long history of Public Utility Regulatory Policies Act (PURPA) implementation over nearly four decades, resulting in more than 4,000 megawatts (MWs) of QF power in operation.[3] Many of the state's first investments in renewable and efficient natural gas generation stem from the Commission's implementation of PURPA.

Under PURPA, an independently-owned generation facility (i.e. a facility not owned by a regulated utility) that meets certain federal eligibility requirements based on size, technology and/or efficiency requirements is entitled to sell its power to regulated utilities at those utilities' avoided cost. These generators are referred to as "Qualifying Facilities" or "QFs."[4] Both cogeneration facilities (also referred to as "combined heat and power" or "CHPs") meeting certain thermal efficiency requirements and renewable

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[2] 18 C.F.R. § 292.304(d)(2).

[3] *See* Commission Decision (D.) 02-08-071 at pages 26-28 for an overview of PURPA-related requirements.

[4] "Qualifying Facility" is defined at 18 C.F.R. § 292.101(b)(1).

energy facilities meeting certain technological requirements can be QFs. The utilities' obligation to purchase electricity offered for sale by QFs is referred to as the "mandatory purchase,"[5] or "must take" obligation.

PURPA provides that a utility may not be required to pay a rate to a QF that "exceeds the *incremental cost* to the electric utility of alternative electric energy."[6] The Federal Energy Regulatory Commission's (FERC) regulations implementing PURPA refer to this "incremental cost" as "*avoided cost*," which FERC defines as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate or purchase from another source."[7] PURPA also requires that the rate paid to QFs by the utility be "just and reasonable to electric consumers of the electric utility and in the public interest" and that it not discriminate against QFs.[8]

Under FERC's regulations implementing PURPA, a QF has the option to provide energy or capacity or both to a utility pursuant to a legally-enforceable obligation.[9] State regulators often implement PURPA by requiring regulated utilities to offer standard contracts to QFs with pro forma terms available for ready execution, commonly referred to as "standard offer contracts" or "SOCs." If a QF elects to obtain a contract for energy or capacity or both, the QF may determine, prior to the specified term of the contract, to be paid rates "based on either (i) The avoided costs calculated at the time of delivery; or (ii) The avoided costs calculated at the time the obligation is incurred."[10] Alternatively, QFs and utilities may agree to a rate, terms, or conditions "which differ from the rate, or

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[5] 16 U.S.C. § 824a-3(m).

[6] 16 U.S.C. § 824a-3(b) (*emphasis added*).

[7] 18 C.F.R. § 292.101(b)(6); *see also* 16 U.S.C. § 824a-3(b).

[8] 16 U.S.C. § 824a-3(b); *see also* 18 C.F.R. § 292.304(a).

[9] 18 C.F.R. § 292.304(d)(2).

[10] 18 C.F.R. § 292.304(d)(2).

terms and conditions which would otherwise be required by [Subpart C of the 18 C.F.R., Part 292]."[11] Instead of signing a contract, QFs also have the option under FERC's regulations to sell energy on an as available basis, with the avoided cost calculated at the time of delivery.[12]

As part of its PURPA implementation obligation, the Commission must identify the regulated utilities' avoided costs. Since these avoided costs, and methods for identifying them, are varied and have evolved over time in conjunction with electricity markets and the availability of more information, the Commission has undertaken multiple proceedings to update its avoided cost determinations over the past decades. In addition, in the past two decades, the Commission has used PURPA to facilitate California's energy policy goals and objectives, sometimes based on its own authority and sometimes pursuant to legislative directives.

The following discussion provides background on some of the Commission's more recent PURPA implementation efforts and avoided cost determinations.

1.1. QF/CHP Settlement Agreement Background

In April 2004, the Commission opened Rulemaking (R.) 04-04-025 to develop a common methodology, consistent input assumptions and updating procedures for avoided costs across various Commission proceedings, and to then adopt avoided cost calculations and forecasts based on this work.[13] In September 2007, the Commission adopted D.07-09-040, which created a new avoided cost pricing methodology and provided general direction for a new SOC to be made available to all QFs. For a number of reasons, there were delays in implementing D.07-09-040. Consequently, the active parties eventually submitted a settlement agreement to resolve the matters left pending

[11] 18 C.F.R. § 292.301(b)(1).

[12] 18 C.F.R. § 292.304(d)(1).

[13] *See* R.04-04-025 at 2.

after adoption of D.07-09-040. This resulted in the Commission's adoption of D.10-12-035 in December 2010, which approved the QF Settlement Agreement, as well as the terms of the Standard Contract for QFs 20 MW or Less and other pro forma standard contracts.

As part of the QF Settlement Agreement, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company together petitioned FERC to terminate the mandatory purchase obligation[14] for all QFs in California over 20 MW in size. FERC granted that petition in 2011.[15] Consequently, the New QF SOC will only apply to QFs 20 MWs or less.

1.2. Background on Other Avoided Cost Programs

In 2010 the Commission made a number of filings with FERC seeking clarification of various FERC orders regarding PURPA's avoided cost requirements. In response, FERC issued two orders reiterating that the state has a wide degree of latitude in setting avoided cost, and clarifying that states can utilize a multi-tiered avoided cost rate structure, and that this approach is consistent with the avoided cost requirements set forth in Section 210 of PURPA.[16] FERC also clarified that state procurement obligations can be considered when calculating avoided cost, expressly overruling its prior holding from *SoCal Edison* to the extent it was inconsistent with that clarification.[17] Simply put, these two FERC orders confirmed that the Commission may establish different avoided

[14] 16 U.S.C. § 824a-3(m).

[15] *Pacific Gas and Electric Co.*, 135 FERC ¶ 61,234 (2011).

[16] 133 FERC ¶ 61,059 (2010) at PP 24 & 30; *see also* 132 FERC ¶ 61,047 (2010).

[17] 133 FERC ¶ 61,059 (2010) at PP 29-30 (referring to *SoCal Edison*, 71 FERC ¶ 61,269 (1995) at 62,080).

costs for different programs or types of resources and remain in compliance with PURPA.[18]

Based on these FERC decisions, the Commission established a series of programs consistent with its overall policy goals and state laws. These programs include the Renewable Market Adjusting Tariff (ReMAT),[19] the Assembly Bill (AB) 1613 CHP Feed-in Tariff,[20] the Net Surplus Compensation program for net-metered rooftop solar facilities,[21] the QF Settlement Agreement discussed above, and the Bioenergy Market Adjusting Tariff,[22] amongst others. The actions we take today make no changes to these programs.

1.3. Winding Creek Solar LLC v. Carla Peterman, et al.

On December 6, 2017, a federal district court found that the Commission's Standard Contract for QFs 20 MW or Less failed to provide QFs the option to choose energy rates determined either at the time of contract execution or at the time of product delivery as required by 18 C.F.R. §§ 292.304(d)(2)(i) and (ii) (*Winding Creek Order*).[23] As a consequence of this finding, the court also found that the Commission's ReMAT program did not comply with PURPA because there is a cap on procurement under

[18] For additional background on these matters, *see* D.11-04-033.

[19] *See* D.12-05-035.

[20] *See* D.11-04-033.

[21] *See* D.11-06-016.

[22] *See* D.15-09-004 and D.18-05-032.

[23] *Winding Creek Solar, LLC v. Carla Peterman, et al.,* N.D. CA Case No. 13cv04934-JD, Findings of Fact and Conclusions of Law, and Order on Summary Judgment, December 6, 2017 at 15 (*Winding Creek Order*).

ReMAT[24] and because the price that results from the ReMAT auction is not an avoided cost.[25]

Both the Commission and the plaintiff have appealed the *Winding Creek Order* to the Ninth Circuit Court of Appeals.[26] On December 15, 2017, the Commission's then-Executive Director ordered the utilities to suspend both further operation of the Re-MAT program and the issuance of any new ReMAT contracts, consistent with the *Winding Creek Order*.[27]

2. Purpose of Rulemaking

In light of the *Winding Creek Order,* this Rulemaking considers adoption of a New QF SOC with price terms as specified in FERC's PURPA regulations at 18 C.F.R. § 292.304(d)(2) and available to any QF of 20 MW or less seeking to sell electricity in California pursuant to PURPA. We anticipate that the remaining terms of the New QF SOC will be based on the terms of the QF Settlement SOC. However, this Rulemaking will consider whether the New QF SOC should incorporate changes to other terms of the Standard Contract for QFs 20 MW or Less to ensure implementation of PURPA consistent with state and federal laws and regulations. This Rulemaking will also consider adoption of a price to be paid at the time of delivery where a QF has opted to sell as-available energy to the utility without a contract.

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[24] *Id.* at 13.

[25] *Id.* at 14.

[26] *Winding Creek Solar, LLC v. Carla Peterman, et al.,* 9th Circuit Case Nos. 17-17531 and 17-17532 (cross-appeals).

[27] The *Winding Creek Order* has no impact on the validity of already-executed contracts, and those contracts should continue with full force and effect.

3. Preliminary Scoping Memo

This Rulemaking will be conducted in accordance with Article 6 of the Commission's Rules of Practice and Procedure, "Rulemaking."[28] As required by Rule 7.1(d), this Rulemaking includes a preliminary scoping memo as set forth below, and preliminarily determines the category of this proceeding and the need for hearing.

The scope of this proceeding is intended to be narrow; we are considering adoption of (1) a New QF SOC containing avoided costs rates required by federal regulations, and (2) adoption of a price to be paid at the time of delivery where a QF has opted to sell as-available energy to the utility without a contract.

We anticipate that the New QF SOC will be the foundation of the Commission's PURPA compliance in that it will meet all of the contracting requirements established in FERC's regulations implementing PURPA, and it will be available to all QFs of 20 MWs or less seeking to sell electricity to Commission-jurisdictional utilities.

This Rulemaking is not intended to change or interfere in any manner with existing PURPA contracts between California investor-owned utilities and QFs, with any currently available PURPA contracts, with any existing PURPA program to the extent allowed by law, or with any aspect of the QF Settlement approved in D.10-12-035.

3.1. Issues

The main issues to be addressed in this proceeding are as follows as they relate to the New QF SOC and the price for as-available energy sold to the utility without a contract.:

1. What is the appropriate avoided cost for <u>energy</u> where a QF elects to be paid a price determined at the time of contract execution?
2. What is the appropriate avoided cost for <u>capacity</u> where a QF elects to be paid a price determined at the time of contract execution?

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[28] All references to "Rules" are to the Commission's Rules of Practice and Procedure unless otherwise indicated.

3. What is the appropriate avoided cost for energy where a QF elects to be paid a price determined at the time of delivery?
4. What is the appropriate avoided cost for capacity where a QF elects to be paid a price determined at the time of contract delivery?
5. What is the appropriate avoided cost calculated at the time of delivery for as-available energy sold by a QF to the utility without a contract?
6. Does PURPA require that any of the non-price terms of the Standard Contract for QFs 20 MW or Less be modified before they are incorporated into the New QF SOC?
7. Are there any other issues that the Commission must address to adopt a New QF SOC that complies with PURPA?

3.2. Establishing Avoided Cost – Staff Pricing Proposal

To facilitate focus on the first five issues identified above, we attach to this Rulemaking a Staff Pricing Proposal. The Staff Pricing Proposal contains proposed prices or price formulas for each of the pricing categories identified in Section 3.1 above.

In response to the Staff Pricing Proposal, we seek comments to this Rulemaking including detailed responses to the following questions:

1) Is the proposed energy price at the time of delivery consistent with PURPA?
2) Is the proposed energy price at the time of contract execution consistent with PURPA?
3) Is the proposed capacity price at the time of delivery consistent with PURPA?
4) Is the proposed capacity price at the time of contract execution consistent with PURPA?
5) Is the proposed energy price for as-available energy sold by a QF to the utility without a contract consistent with PURPA?
6) Are there any other terms of the Standard Contract for QFs 20 MW or Less that should be modified to ensure that the New QF SOC is consistent with PURPA?

4. Categorization and *Ex Parte* Communications

As a preliminary matter, we determine that this proceeding is ratesetting Accordingly, *ex parte* communications are restricted and must be reported pursuant to Article 8.

5. Need for Hearing

It is preliminarily determined that evidentiary hearings will not be needed in this proceeding.

6. Preliminary Schedule

The preliminary schedule for this Rulemaking is set forth below. The assigned Commissioner and/or the assigned Administrative Law Judge may revise the schedule to develop an adequate record, conduct this proceeding in an orderly manner, and achieve a fair resolution of this proceeding. We expect to resolve this proceeding on an expedited schedule in order to address certain aspects of the *Winding Creek Order.*

Date	Event
July 26, 2018	Rulemaking adopted
30 days from issuance of Rulemaking	Respondents must, and other parties may, file and serve comments in response to initial scoping questions
45 days from issuance of Rulemaking	Reply Comments filed and served
September/October 2018	Prehearing Conference
To be determined	Issuance of assigned Commissioner's Scoping Memo
To be determined in Scoping Memo	Additional record development (as determined in Scoping Memo)
To be determined in Scoping Memo	Proposed Decision
No sooner than 30 days after the Proposed Decision	Final Decision

We anticipate that the issues in this proceeding will be resolved within six months of initiation of this Rulemaking; however, the Commission will resolve this proceeding not later than the 18-month statutory deadline pursuant to Public Utilities Code Section 1701.5(a)

Although the preliminary procedural schedule does not contemplate workshops, in the event that workshops are held in this proceeding, notice of such workshops will be posted on the Commission's Daily Calendar to inform the public that a decision-maker or an advisor may be present at those meetings or workshops. Parties shall check the Daily Calendar regularly for such notices.

7. Respondents

The state's investor-owned electric utilities, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, PacifiCorp, Bear Valley Electric, and Liberty Utilities are named as Respondents to this Rulemaking.

8. Service of Rulemaking

This Rulemaking shall be served on all respondents. In addition, the Executive Director shall effect service on the service lists for the following proceedings:

1. R.04-04-025 (the last general avoided cost proceeding)
2. R.15-02-020 (Renewables Portfolio Standard)
3. R.16-02-007 (Integrated Resource Planning)

Service of the Rulemaking does not confer party status or place any person who has received such service on the Official Service List for this proceeding, other than respondents. Instructions for obtaining party status or being placed on the official service list are provided below.

9. Becoming a Party: Joining and Using the Service List

If the Rulemaking names you as respondent, you are already a party, but you or your representative must still ask to be added to the official service list.

Within 15 days of mailing of this rulemaking, each respondent shall inform the Commission's Process Office of the contact information for a single representative, although other representatives and persons affiliated with the respondents may be placed on the Information Only service list.

We will provide for service of this order on the service list for all of the proceedings listed in Section 8, of this order.

Such service does not confer party status. If you want to participate in the rulemaking or simply to monitor it, follow the procedures set forth below. To ensure you receive all documents, send your request within 30 days after the Rulemaking is published. The Commission's Process Office will publish the official service list at the Commission's website (www.cpuc.ca.gov), and will update the list as necessary.

9.1. During the First 30 Days

Within 30 days of the service of this Rulemaking, any person may be added to the official service list by sending a request to the Process Office. You may use e-mail (Process_Office@cpuc.ca.gov) or letter (Process Office, California Public Utilities Commission, 505 Van Ness Avenue, San Francisco, CA 94102). Include the following information:

- Docket Number of this Rulemaking;
- Name (and party represented, if applicable);
- Postal Address;
- Telephone Number;
- E-mail Address; and
- Desired Status (Party, State Service, or Information Only).[29]

Party status will be granted to any party upon timely receipt of the above information.

[29] If you want to file comments or otherwise actively participate, choose "Party" status. If you do not want to actively participate but want to follow events and filings as they occur, choose "State Service" status if you are an employee of the State of California; otherwise, choose "Information Only" status.

9.2. After the First 30 Days

If you want to become a party after the first 30 days, you may do so by making an oral motion at the prehearing conference (Rule 1.4(a)(3)), or by filing a motion (Rule 1.4(a)(4)). If you file a motion, you must also comply with Rule 1.4(b). These rules are in the Commission's Rules of Practice and Procedure, which you can read at the Commission's website www.cpuc.ca.gov.

If you want to be added to the official service list as a non-party (that is, as State Service or Information Only), follow the instructions in Section 9.1 above.

9.3. Updating Information

Once you are on the official service list, you must ensure that the information you have provided is up-to-date. To change your postal address, telephone number, e-mail address, or the name of your representative, send the change to the Process Office by letter or e-mail, and send a copy to everyone on the official service list.

9.4. Serving and Filing Documents

We anticipate that the Process Office will not publish the official service list before the first filing deadline in this Rulemaking. Until the official service list is published, the official service lists for R.04-04-025, R.15-02-020, and R.16-02-007 shall be used as the temporary official service list.

When you serve a document, use the official service list published at the Commission's website as of the date of service. You must comply with Rules 1.9 and 1.10 when you serve a document to be filed with the Commission's Docket Office. If you are a party to this Rulemaking, you must serve by e-mail any person (whether Party, State Service, or Information only) on the official service list who has provided an e-mail address.

The Commission encourages electronic filing and e-mail service in this Rulemaking. You may find information about electronic filing at http://www.cpuc.ca.gov/PUC/efiling.

E-mail service is governed by Rule 1.10. The subject line for e-mail communications should include the proceeding number, and where the filing is related to a specific track, the track number for the filing. In addition, the party sending the e-mail should briefly describe the attached communication, for example, *Brief.* If you use e-mail service, you must also provide a paper copy to the assigned Administrative Law Judge. The electronic copy should be in Microsoft Word or Excel formats to the extent possible. The paper copy should be double-sided. E-mail service of documents must occur no later than 5:00 p.m. Pacific Time on the date that service is scheduled to occur.

If you have questions about the Commission's filing and service procedures, contact the Docket Office.

10. Public Advisor

Any person or entity interested in participating in this rulemaking who is unfamiliar with the Commission's procedures should contact the Commission's Public Advisor in San Francisco at (415) 703-2074 or (866) 849-8390 or e-mail public.advisor@cpuc.ca.gov; or in Los Angeles at (213) 576-7055 or (866) 849-8391, or e-mail public.advisor.la@cpuc.ca.gov. The TTY number is (866) 836-7825.

11. Intervenor Compensation

Any party that expects to claim intervenor compensation for its participation in this rulemaking shall file its notice of intent (NOI) to claim intervenor compensation no later than 30 days after the prehearing conference.

12. *Ex Parte* Communications

Communications with decision makers and advisors in this rulemaking are subject to the rules on *ex parte* communications set forth in Article 8 of the Rules of Practice and Procedure. (*See*, e.g., Rules 8.2(c), 8.3, and 8.4(b))

O R D E R

IT IS ORDERED that:

1. The Commission institutes this Order Instituting Rulemaking on its own motion pursuant to Rule 6.1 of the Commission's Rules of Practice and Procedure to continue its implementation of the Public Utility Regulatory Policies Act of 1978.
2. The preliminary categorization is ratesetting.
3. The preliminary determination is that a hearing is not needed.
4. The preliminary scope of this Rulemaking is as set forth in Section 3. Scope, above. The assigned Commissioner may refine the scope of the Rulemaking initiated by this Order.
5. The preliminary schedule for this Rulemaking is as set forth in Section 6, above. The assigned Commissioner and/or the assigned Administrative Law Judge may modify the schedule to develop an adequate record, conduct this proceeding in an orderly and efficient manner, and achieve a fair resolution of this proceeding. The schedule for the remainder of the proceeding will be adopted in the Assigned Commissioner's Scoping Memo.
6. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, PacifiCorp, Bear Valley Electric Service, a division of Golden State Water Company, and Liberty Utilities are named as respondents to this Rulemaking.
7. The respondents shall, and any other person may, file comments responding to this Rulemaking within 30 days of the issuance of this Order Instituting Rulemaking. Reply comments are due within 45 days of issuance of this Order Instituting Rulemaking.
8. The deadline to file and serve notices of intent to claim intervenor compensation is 30 days after the date of the prehearing conference.
9. The Executive Director will cause this Order Instituting Rulemaking to be served on the respondents and on the service lists for the following Commission proceedings:

- Rulemaking 04-04-025
- Rulemaking 15-02-020
- Rulemaking 16-02-007

This order is effective today.

Dated July 26, 2018, at Sacramento, California.

MICHAEL PICKER
President
CARLA J. PETERMAN
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
Commissioners

ATTACHMENT

Proposal to Update Avoided Cost Pricing for Qualifying Facilities of 20 MW or Less

An Energy Division Staff Proposal

California Public Utilities Commission

July 2018

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Tables

Figures

Chapter 1: Introduction

Background on Avoided Cost Pricing and QF Settlement

The Order Instituting Rulemaking (OIR) contains background on avoided cost pricing for Qualifying Facilities (QFs) in California and the QF Settlement, which will not be repeated here. Staff notes, however, that avoided cost pricing has been in place since the 1980s and some historical information is available for Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E).[1]

Purpose and Summary

The purpose of this Staff Proposal is to recommend avoided cost pricing for a new standard offer contract for qualifying facilities (QFs) that are less than or equal to 20 MW in size. Staff proposes methodologies to establish four avoided cost price options for QFs seeking a contract – a time of delivery and a time of execution price for both energy and as-available capacity.

These proposals are summarized below:

- For the **energy at time of delivery** price option, Staff proposes to use hourly prices from the California Independent System Operator's (CAISO's) day-ahead market for energy. This same pricing methodology would apply to energy provided as available to a utility by a QF 20 MW or less with no contract.

- For the **capacity at time of delivery** price option, Staff proposes to use bilateral resource adequacy (RA) prices for yearly capacity payments, with the RA capacity prices shaped to time periods based on generation capacity cost allocation factors adopted by the Commission and applied to updated time-of-use periods on a yearly basis.

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[1] See https://www.pge.com/en_US/for-our-business-partners/energy-supply/prices-for-qualifying-facilities-and-eligible-combined-heat-and-power-facilities/prices-for-different-facilities.page, http://www2.sdge.com/srac/, https://www.sce.com/wps/portal/home/regulatory/renewable-alternative-power/qualifying-facilities-data-documents/!ut/p/b1/vVJNc4IwEP01HjMJJOXjyEiHQkdba50CF2eNAdNiQIxa_n2D41XRS3PazOy-t--9xTlOca7gKEvQslZQ9f_cWSZxGFgRs-PlTUISvIduuPhwLPZqmYbMNJArLyDneT8izy_JG4mjzxklMZ2R6TwIKCEO_sI5zrnSjd7gbM_FktdKC6WXQo3IpR6RVpSHCnTddn2txAlWlUBQadEqs-pRoKY-iXZEdgeoZNFJVaICuKyklmKP1qABrWt-2Bq0fc_YcLnGGXMLzyaOj5hlrRADjyIg4KEn2xWc-p7PeHFReEPCgENnhQMeDbmUmR3cqyRjhucPihoAdB4GTO44FPm92-WBibuP9Vfj9J_yNtR2OxlPSqMI9AZJVdQ4vYGL07twm-1i69EO_RTTKYKV19Gq_ANbUiha/dl4/d5/L2dBISEvZ0FBIS9nQSEh/

- For the **energy at time of contract execution** price option, Staff proposes to use a three-year average of energy prices obtained from the CAISO's day-ahead energy market. Staff notes that these prices have remained fairly constant over this time period, that these prices are consistent with long-term prices for energy executed recently, and that prices could increase or decrease, depending on the penetration of renewables (which could exert downward pressure on market heat rates and prices) and fuel prices (which could exert downward or upward pressure on prices).

- For the **capacity at time of contract execution** price option, Staff proposes to use either (1) average prices from publicly available bilateral RA contracts, or (2) the capacity prices provided in the existing Standard Contract for QFs 20 MW or less, with time-of-day adjustments.

For both the energy and capacity time of contract execution options, the prices would apply for the duration of the contract term. However, the prices would be recalibrated each year based on currently available time-of-use periods, for QFs seeking contracts during that time.

Chapter 2: Staff Proposal

Chapter Summary

This chapter discusses current avoided cost pricing, changes that have occurred in the market since avoided costs were last developed, newly adopted time-of-use periods for the investor owned utilities (IOUs), as well as Staff's proposals for time of delivery and time of execution avoided cost pricing options for both energy and as-available capacity.

Current Avoided Cost Pricing

Currently available avoided cost pricing option for both energy and capacity were determined by a settlement approved in D.10-12-035 and Resolution E-4246.[2] At a very high level, current avoided cost energy prices are based on a forward market heat rate, burnertip gas prices, variable operation and

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[2] D.10-12-035, December 16, 2010, as modified, available here:
http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/128624.PDF,
Resolution 4246-E, available here:
http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_RESOLUTION/104168.PDF,

maintenance costs, and time-of-use adjustment factors. Appendix A to this Staff Proposal contains the June 2018 short-run avoided cost (SRAC) calculations for PG&E, SCE, and SDG&E, including the formulas, inputs and the calculated SRAC for each investor-owned utility (IOU), by time period. The monthly weighted average energy prices for June 2018 for PG&E, SCE, and SDG&E are $33.790/MWh, $34.516/MWh and $35.821/MWh, respectively, as shown in Appendix A.

The current time-of-use periods and time-of-use factors for the three IOUs are shown in Tables 1, 2 and 3 below.

Table 1. Current PG&E Energy Only Time-of-Use Periods for SRAC Energy Prices and TOU Factors[3]

	Summer **May 1 – Oct 31**	**Winter** **Nov 1 – April 30**	**Applicable Days**
Peak	Noon – 6 pm	NA	Weekdays except Holidays
TOU Factor	1.0254	NA	
Partial-Peak	8:30 am – Noon 6:00 pm – 9:30 pm	8:30 am – 9:30 pm	Weekdays except Holidays Weekdays except Holidays
TOU Factor	1.2001	1.1224	
Off-Peak	9:30 pm – 1:00 am 5:00 am – 8:30 am 5:00 am – 1:00 am	9:30 pm – 1:00 am 5:00 am – 8:30 am 5:00 am – 1:00 am	Weekdays except Holidays Weekdays except Holidays Weekends and Holidays
TOU Factor	Varies by month, weighted by hours (June – 1.0440)	Varies by month, weighted by hours (April – 0.9365)	
Super Off-Peak	1:00 am – 5:00 am	1:00 am – 5:00 am	All Days
TOU Factor	0.6084	0.8946	

[3] Note that PG&E Energy Price Time of Use Factors change yearly, see the following website for these values: https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/energy-supply/prices-for-qualifying-facilities-and-eligible-combined-heat-and-power-facilities/20180110-Historical-TOU-Factors.pdf.

Table 2. Current SCE Energy Only Time-of-Use Periods for SRAC Energy Prices and TOU Factors[4]

	Summer June 1 – Sept 30	Winter Oct 1 – May 31	Applicable Days
On-Peak	Noon – 6:00 pm	NA	Weekdays except Holidays
TOU Factor	1.4251	NA	
Mid-Peak	8:00 am – Noon 6:00 pm – 11:00 pm	8:00 am – 9:00 pm	Weekdays except Holidays Weekdays except Holidays
TOU Factor	Varies by month, weighted by hours (June – 1.0325)	1.2185	
Off-Peak	11:00 pm – 8:00 am Midnight - Midnight	6:00 am – 8:00 am 9:00 pm – Midnight 6:00 am – Midnight	Weekdays except Holidays Weekdays except Holidays Weekends and Holidays
TOU Factor	0.8526	Varies by month, weighted by hours (April – 0.9234)	
Super Off-Peak	NA	Midnight – 6:00 am	All Days
TOU Factor	NA	0.7760	

Table 3. Current SDG&E Energy Only Time-of-Use Periods for SRAC Energy Prices and TOU Factors

	Summer May 1 – Sept 30	Winter Oct 1 – Apr 30	Applicable Days
Peak	11:00 am – 6:00 pm	5:00 pm – 8:00 pm	Weekdays except Holidays
TOU Factor	1.4110	1.2240	
Semi-Peak	6:00 am – 11:00 am 6:00 pm – 10:00 pm	6:00 am – 5:00 pm 8:00 pm – 10:00 pm	Weekdays except Holidays Weekdays except Holidays
TOU Factor	1.1060	1.1060	
Off-Peak	10:00 pm – Midnight 5:00 am – 6:00 am 5:00 am – Midnight	10:00 pm - Midnight 5:00 am – 6:00 am 5:00 am – Midnight	Weekdays except Holidays Weekdays except Holidays Weekends and Holidays
TOU Factor	0.9860	0.9330	
Super Off-Peak	Midnight – 5:00 am	Midnight – 5:00 am	All Days
TOU Factor	0.6450	0.7110	

As-available capacity prices are based on formulas adopted in D.07-09-040 and D.10-12-035 and are based on a capacity value, less adjustments for ancillary services and energy benefits. The as-available

[4] TOU Factors available at: https://www.sce.com/nrc/aboutsCE/regulatory/qualifyingfacilities/srac_hist.pdf.

capacity value was determined based on the cost a combustion turbine facility, which is then escalated at 2.5 percent each year. The ancillary services and energy benefits were calculated based on the expected ancillary service and energy revenues for participation in energy market, which were not escalated.

The 2018 combustion turbine cost (i.e., the capacity value for 2018) is $86.93/kW-year and is adjusted downward by $14.82/kW-year for ancillary services and $16.78/kWh-year for energy benefits – for a final figure of $55.33/kW-year. This figure is then allocated based on "capacity allocation factors," which allocate the capacity value for seasons and time-of-delivery periods. The capacity allocation factors are based on allocation of the expected allocation of generation capacity costs determined in earlier proceedings (i.e., allocation to summer and winter seasons and various time periods, presumably based on loss of load studies).

Appendix A contains the as-available capacity prices for PG&E, SCE, and SDG&E, including the formulas, inputs and calculated prices. The current capacity allocation factors for the IOUs are shown in the Tables 4, 5, and 6 below.

Table 4. Current PG&E Capacity Allocation Factors, Delivery Hours, and Capacity Energy Only Time-of-Use Periods for SRAC Energy Prices and TOU Factors (for 2018)

	Capacity Allocation Factor	Hours	Capacity Adjustment Factor (year/hour)	Capacity Loss Adjustment Factor (Transmission)	As-Delivered Capacity Price, Transmission ($/kWh)
Summer (May – Oct) - $55.33/kW-Year					
Peak	76.19%	774	0.0009844	0.989	$0.053868
Partial Peak	2.38%	903	0.0000264		$0.001445
Off-Peak	0.02%	2,003	0.0000001		$0.000005
Super Off-Peak	NA	736	0.0000000		
	78.59%	4,416			
Winter (Jan – Apr and Nov and Dec) - $55.33/kW-Year					
Peak	NA	0		0.989	
Partial Peak	21.25%	1,612	0.0001318		$0.007212
Off-Peak	0.15%	2,008	0.0000007		$0.000038
Super Off-Peak	N/A	724	0.0000000		$0.000000
	21.41%	4,344			
Without Time-of-Delivery Metering ($27.665/kW-Year)					
Summer	78.59%	4,416	0.0001780	0.989	$0.0040870
Winter	21.41%	4,344	0.0000493		$0.001352

Table 5. Current SCE Capacity Allocation Factors, Delivery Hours, and Capacity Energy Only Time-of-Use Periods for SRAC Energy Prices and TOU Factors (for 2018)[5]

	Capacity Allocation Factor	Hours	Capacity Adjustment Factor (year/hour)	Capacity Loss Adjustment Factor (Transmission)	As-Delivered Capacity Price, Transmission ($/kWh)
Summer (Jun – Sept) - $55.33/kW-Year					
On-Peak	71.68%	504	0.0014222		$0.0787
Mid-Peak	12.4%	756	0.0001640		$0.0091
Off-Peak	0.24%	1,668	0.0000014		$0.0001
Super Off-Peak	NA	NA	0.0000000		
	84.32%	2,928			
Winter (Jan – May and Oct – Dec) - $55.33/kW-Year					
On-Peak	NA	NA			
Mid-Peak	14.24%	2,197	0.0000648		$0.0036
Off-Peak	0.88%	2,177	0.0000040		$0.0002
Super Off-Peak	0.56%	1,458	0.0000038		$0.0002
	15.68%	5,832			
Without Time-of-Delivery Metering ($27.665/kW-Year)					
Summer	84.32%	2,928	0.0002885		$0.0080
Winter	15.68%	5,832	0.0000269		$0.0007

[5] Note that Staff calculated the capacity adjustment factor from SCE's monthly conversion factors and hours in each time-of-use period.

Table 6. Current SDG&E Capacity Allocation Factors, Delivery Hours, and Capacity Energy Only Time-of-Use Periods for SRAC Energy Prices and TOU Factors (for 2018)

	Capacity Allocation Factor	Hours	Capacity Adjustment Factor (year/hour)	Capacity Loss Adjustment Factor	As-Delivered Capacity Price, Transmission ($/kWh)
Summer (May – Sept) - $55.33/kW-Year					
Peak	72.79%	742	0.000980960		$0.054277
Semi-Peak	5.86%	954	0.000006146		$0.003401
Off-Peak	0.0%	1,211	0.0		$0.0
Super Off-Peak	0.0%	765	0.0		$0.0
	78.65%	3,672			
Winter (Jan – Apr and Oct – Dec) - $55.33/kW-Year					
Peak	5.84%	441	0.00013237		$0.007324
Semi-Peak	15.51%	1911	0.00008118		$0.004492
Off-Peak	0.0%	1,676	0.0		$0.0
Super Off-Peak	0.0%	1,060	0.0		$0.0
	21.35%	4,344			
Without Time-of-Delivery Metering ($27.665/kW-Year)					
Summer	78.65%	3,672	0.00002142		$0.005926
Winter	21.35%	5,088	0.00000418		$0.001155

Market Changes Since Avoided Costs Were Developed

The current time periods used in the avoided costs described above were developed at a time when the system peaked in the middle of the day, typically during the noon to 6 pm time period. However, over the past decade, the system peaks in both the summer and winter have shifted later in the day, due to the large influx of behind-the meter solar resources. In addition, the net peak and the higher priced periods have also shifted later, as shown in the following graphs. Typical net peaks for summer and winter have also shifted later as solar capacity has grown.

This is illustrated in Figures 1 and 2, , which provide load and net load shapes for typical summer and winter days.[6]

[6] Load and renewables data is taken from the dataset used for the CAISO 2019 Flexible Capacity Requirements Study. Figure 1 depicts August 28, 2017 and Figure 2 depicts February 15, 2017.

Figure 1. Typical Summer Load and Net Load Shape

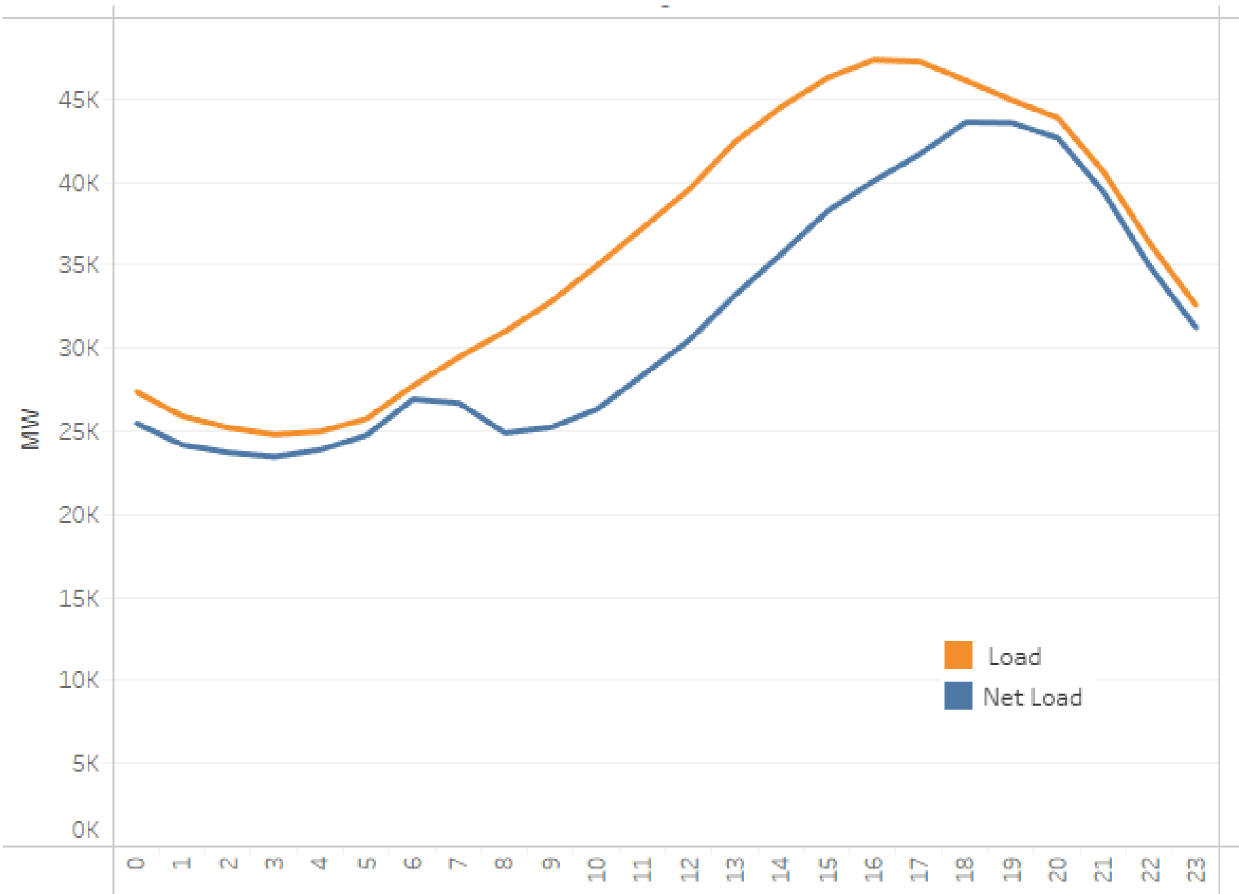
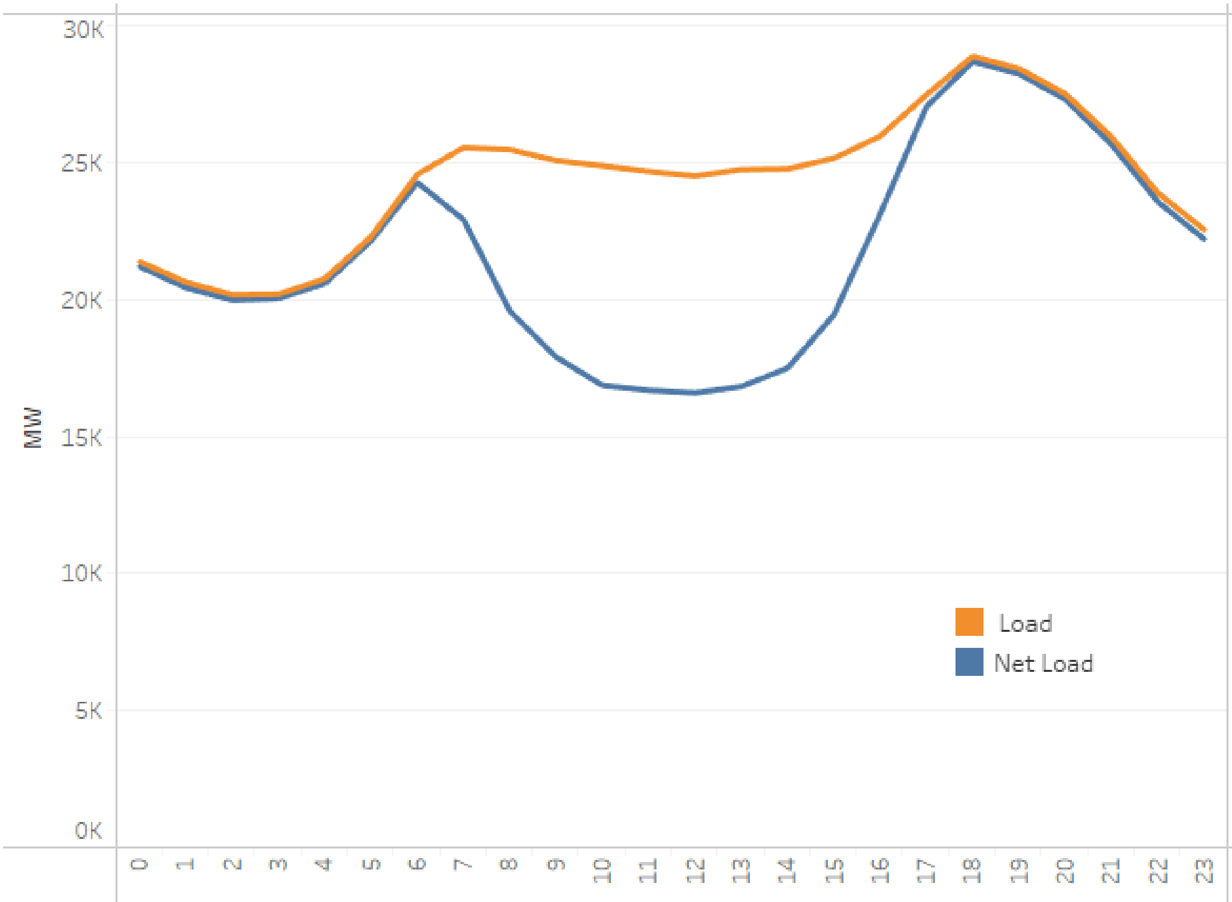


Figure 2. Typical Winter Load and Net Load Shape



Figures 3 and 4 illustrate this in a different manner, with average and maximum system loads for each month and hour for 2017. As these figures illustrate, the peaks no longer occur during the noon to 6 pm period, but have shifted to later in the day.

Figure 3. Average 2017 System Load by Month and Hour

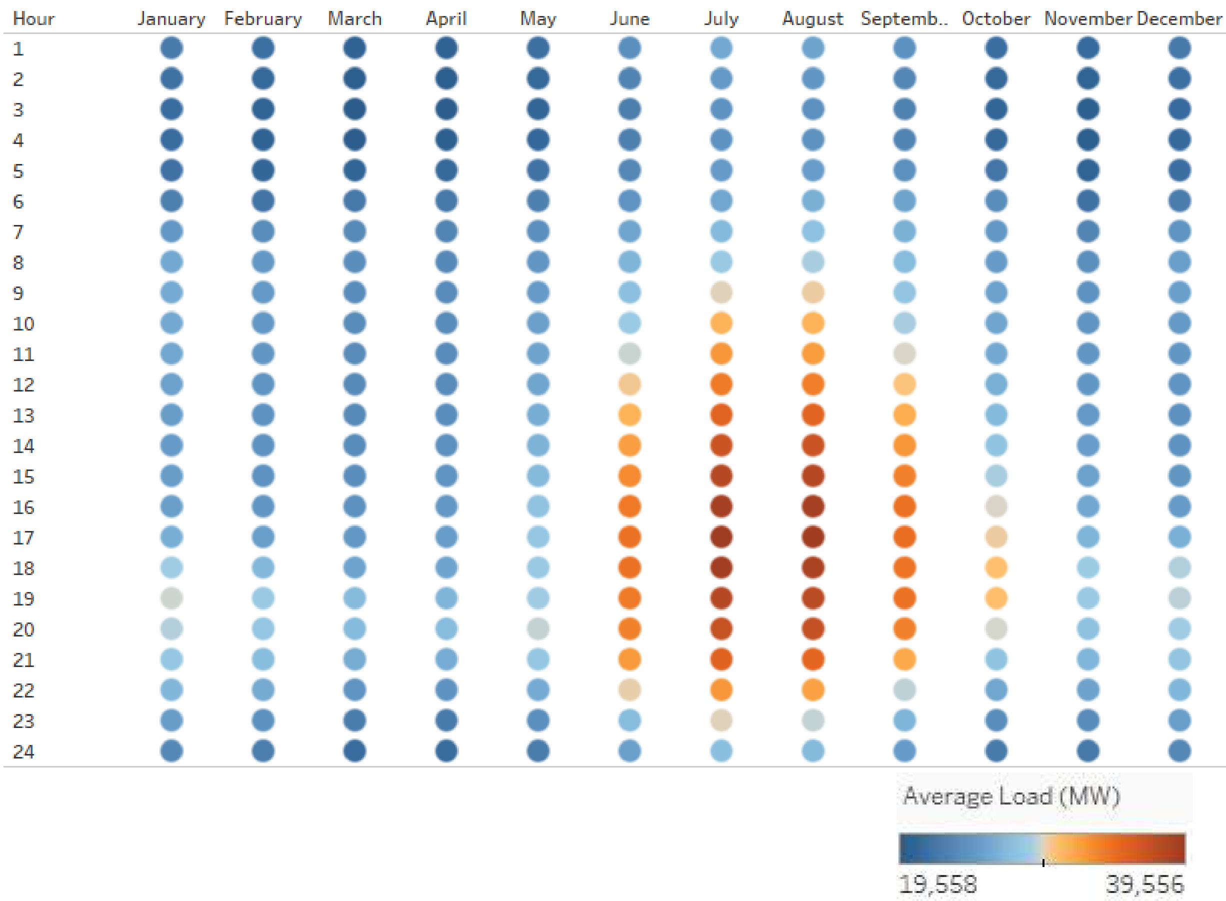
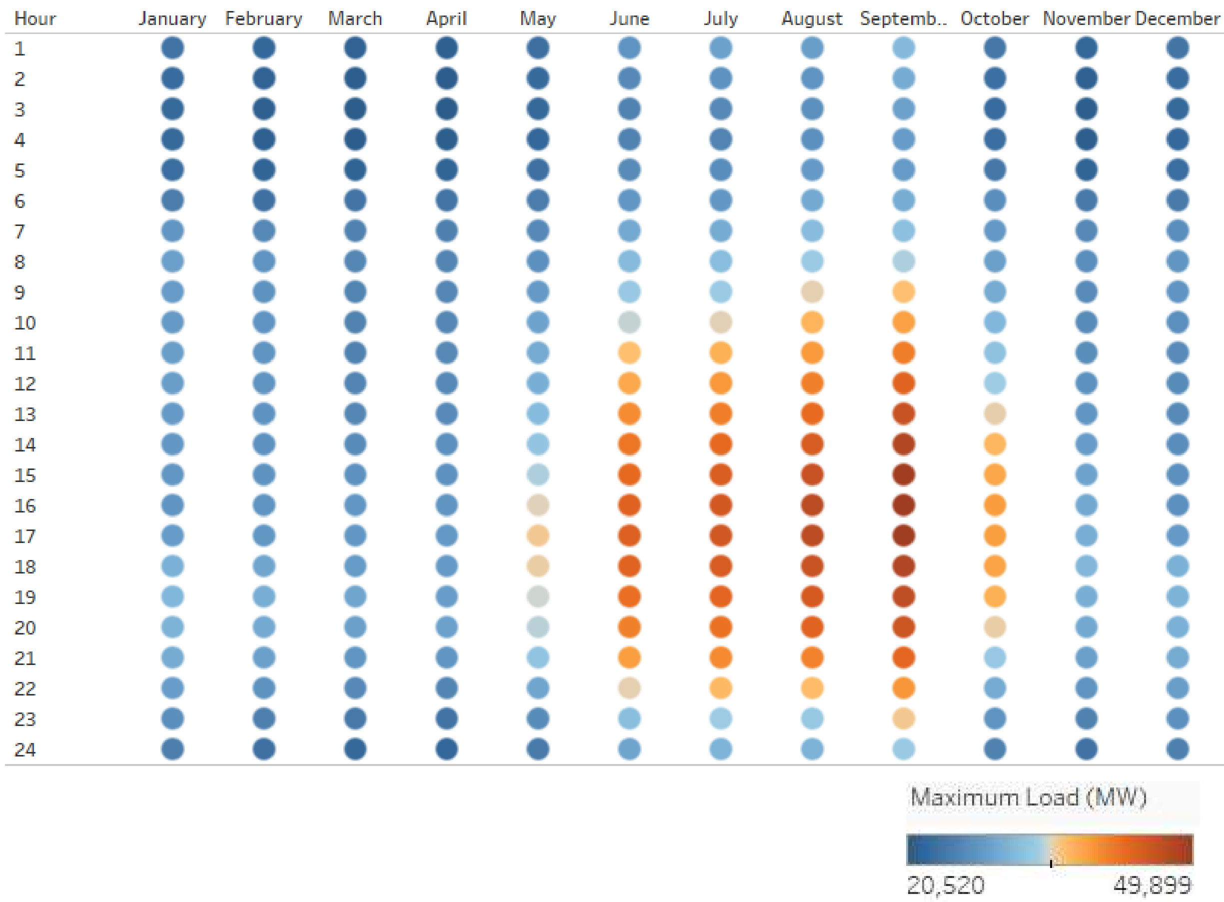


Figure 4. Maximum 2017 System Load by Month and Hour



Figures 5 and 6 also illustrate that high prices are now seen later in the day, reflecting the changing load and net load patterns. In addition, prices during the mid-day period are now considerably lower due to the influx of solar resources. Given low loads and high penetrations of renewables, prices during the mid-day period are particularly low during spring months, March through May (the dark blue circles during these months).

Figure 5. Average Day-Ahead Market Price by Month and Hour

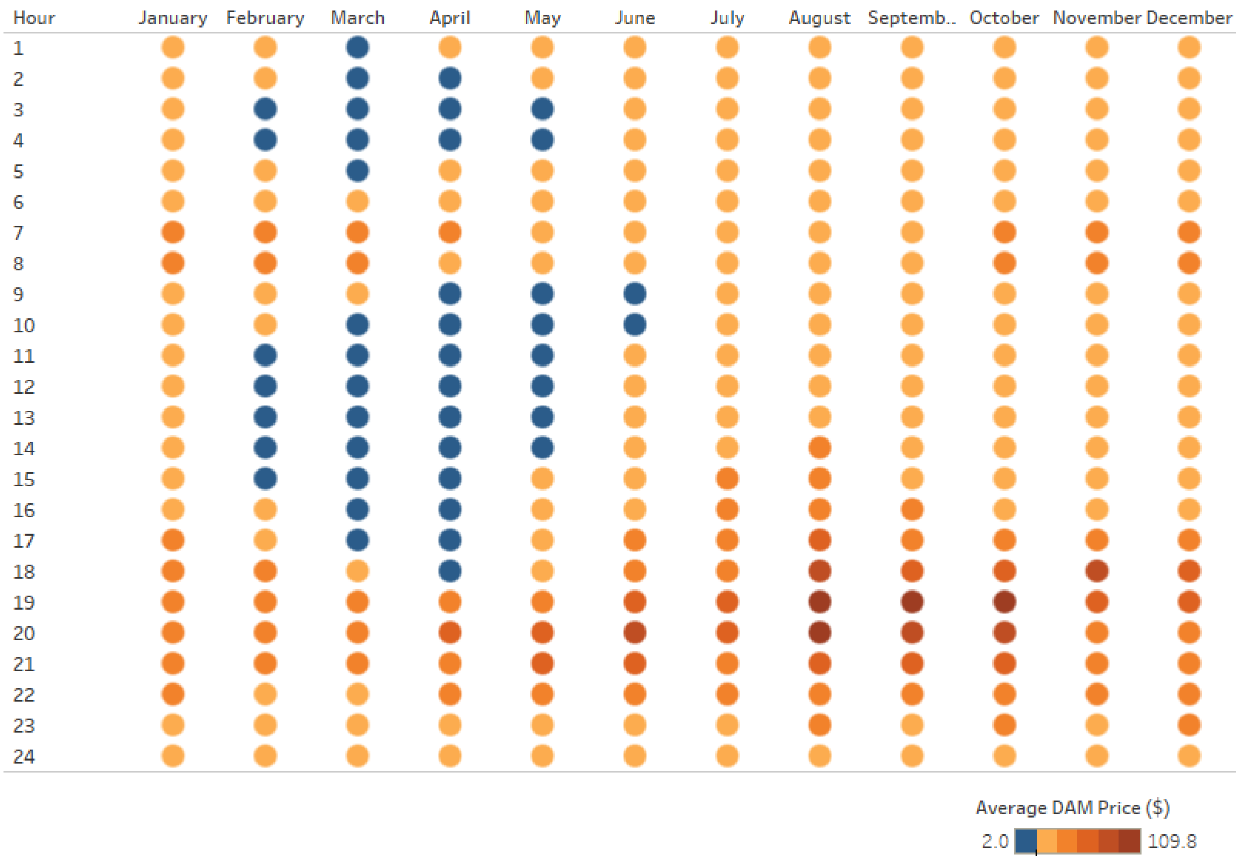
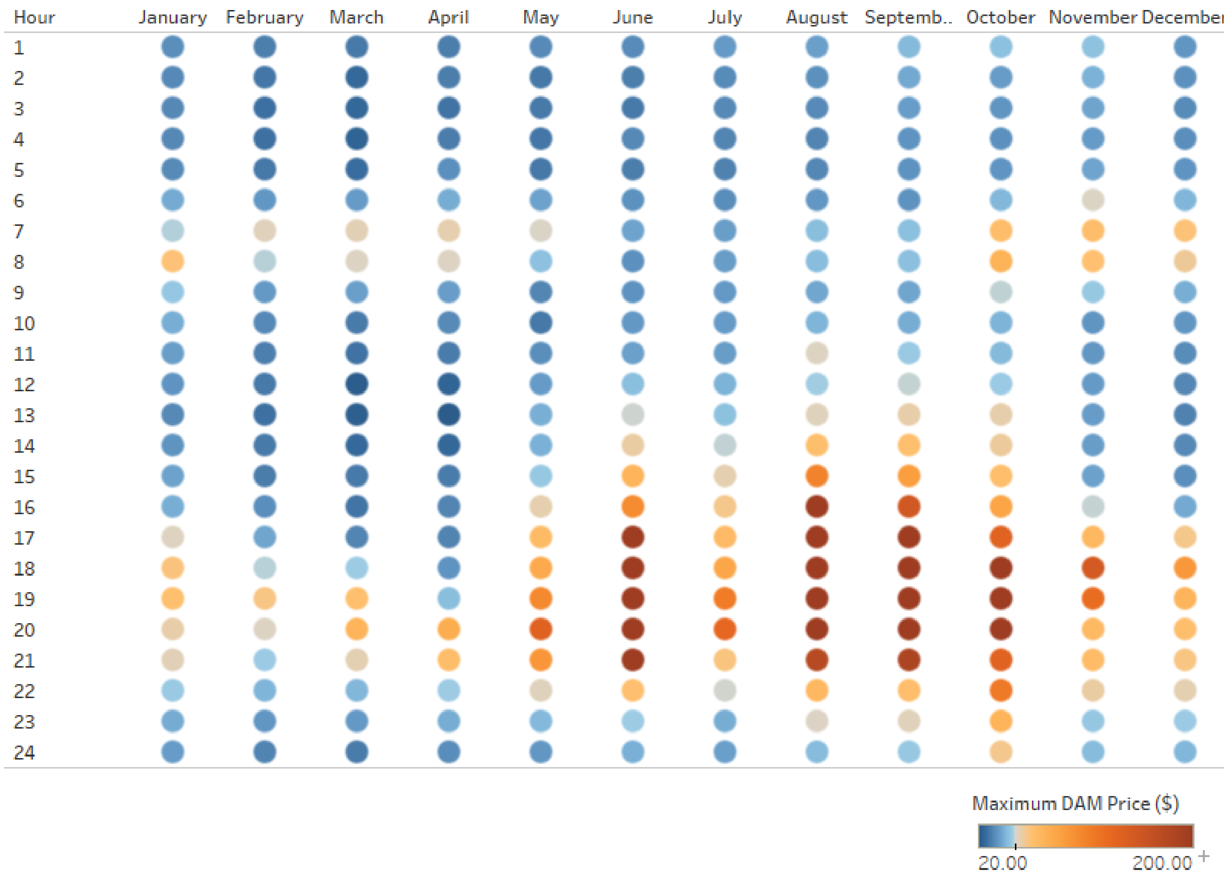


Figure 6. Maximum Day-Ahead Market Price by Month and Hour



Changing Time-of-Use Periods

Recent Commission decisions and proposed decisions have changed or proposed changing the time-period definitions for the IOUs. In D.17-08-030, the Commission adopted 4 pm – 9 pm as the peak period for SDG&E, largely based on load and price analyses. The Commission concluded the following:

> SDG&E's current standard TOU period includes a summer on-peak period of 11 a.m. to 6 p.m. on non-holiday weekdays and has been in effect since the 1980s. However, "deployment of grid-connected and behind-the-meter solar has increased the availability of energy during the afternoon and decreased the load on the grid. As a result, the peak periods, in terms of grid needs and cost, have shifted to later in the day. In addition, on spring days with low demand and high solar generation, there is a risk that there will be an excess of generation available, leading to curtailment of renewables and other resources." (D.17-01-006 at 5.) "The California Independent System Operator (CAISO)… has been particularly concerned with times when the available renewable generation is high but load is low. This situation has forced CAISO to curtail a small percentage of renewable generation. CAISO argues that in addition to peak periods, matinee rates (aka reverse demand response) with super-off peak periods during spring days may be necessary." (D.17-01-006 at 5-6, citations omitted.) "[A]nalyses show three phenomena

affecting the setting of TOU periods: peak shift, spring over generation, and steep ramp." (D.17-01-006 at 14.)[7]

As a result of its analysis of the evidence regarding these phenomenon, in D.17-08-030, the Commission adopted peak period time periods extending from 4 pm – 9 pm daily; super off-peak periods extending from midnight to 6 am all days, 6 am – 2 pm on weekends and holidays, and 10 am – 2 pm on weekdays in March and April, with all other times falling into the off-peak period.[8] In addition, D.17-08-030 adopted a five-month summer season (June – October), rather than SDG&E's proposed continuation of its six-month summer (May – October) season.

In a recent proposed decision in SCE's 2016 Rate Design Window application (A.16-09-003), the Administrative Law Judge proposed retaining SCE's current definitions of two seasons, summer (June – September) and winter (October – May), but proposed establishing new base TOU periods "to reflect the changing energy market:"[9]

- An on-peak period of 4 pm – 9 pm, summer weekdays;
- A mid-peak period of 4 pm – 9 pm, summer weekends and winter weekdays and weekends;
- A super off-peak period from 8 am – 4 pm for winter weekdays and weekends;
- An off-peak period in the summer and winter for all other hours.

The proposed decision is currently before the Commission for consideration.

Finally, PG&E and parties have submitted a settlement agreement in A.16-06-013, which proposes to define its summer season, as June – September, from the current six-month summer season, May – October, and to update its time of use periods, as follows:

- A peak period of 4 pm – 9 pm, all days of the year;
- A part-peak period of 2 – 4 pm and 9 pm – 11 pm, all days, summer only;
- A super off-peak period of 9 am to 2 pm in March, April and May only;
- An off peak period in the summer and winter for all other hours.

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[7] D.17-08-030, pp. 18-19, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M194/K599/194599448.PDF.
[8] D.17-08-030, pp. 25-26.
[9] Proposed Decision in A.16-09-003, p. 2 and Appendix 2, available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M214/K794/214794441.PDF.

Proposed Avoided Cost Pricing Methodologies

Staff proposes four avoided cost pricing methodologies for a new standard offer contract for QFs 20 MW or less – one each for energy and as-available capacity at both time of delivery and time of contract execution. These pricing proposals are discussed further below.

Staff Time of Delivery Energy Proposal

Staff proposes to use hourly prices from the CAISO's day-ahead market to establish the avoided cost price available for energy priced at the time of delivery. Specifically, Staff proposes to use either the hourly prices at the default load aggregation point (DLAP) or the locational marginal price (LMP) for the resource itself. The day-ahead hourly market prices represented by DLAP would be an aggregated number, but the LMP would be specific to the QF resource and may be more accurate.

Staff notes that the day-ahead market prices may move to 15-minute granularity and, if that were to occur, Staff recommends use of the 15-minute day-ahead prices. Staff also notes that in some hours, prices could be negative due to excess energy on the system and Staff proposes that these negative prices apply in these hours or 15-minute increments.

Staff Time of Delivery As-Available Capacity Proposal

To establish the avoided cost price available for as-available capacity priced at the time of delivery, Staff proposes to rely on average RA market prices that are publicly available, and to shape them by TOU period and generator capacity.[10] The CPUC's 2017 Resource Adequacy report concludes that the weighted average capacity price for 2016-2020 is \$2.77/kW-month or \$33.24/kW-year.[11]

To allocate capacity costs for the illustrative tables below, Staff used the existing capacity allocation factors, but applied them the revised TOU periods. Illustrative revised time-periods and TOU factors for the three IOUs are shown in Tables 7, 8 and 9 below. Staff notes that the capacity allocation factors would need to be updated to reflect more recent Commission decisions on TOU periods and loss-of-load probabilities on a yearly basis. This process would involve: 1) identifying Commission approved generation capacity allocation factors, 2) identifying Commission approved time-of-use periods, and 3) allocating adopted capacity costs to the time of use periods based on the generation capacity allocation factors.

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[10] Energy Division Staff Resource Adequacy reports for 2006 – 2016 are available at: http://www.cpuc.ca.gov/General.aspx?id=6307.
[11] See Energy Division, "2016 Resource Adequacy Report," June 2017, p. 23.

Table 7. Illustrative PG&E As-Available Capacity Prices

	Capacity Allocation Factor	Hours	Capacity Adjustment Factor (year/hour)	Capacity Loss Adjustment Factor (Transmission)	As-Delivered Capacity Price, Transmission ($/kWh)
Summer (Jun – Sep) - $33.24/kW-Year					
Peak	76.19%	610	0.00124902	0.989	$0.041061
Partial Peak	2.38%	488	0.00004877		$0.001603
Off-Peak	0.02%	1,830	0.00000011		$0.000000
Super Off-Peak	NA	NA	0		
	78.59%	2,928			
Winter (Jan – May and Oct -- Dec) - $33.24/kW-Year					
Peak	21.25%	1,215	0.00017490	0.989	$0.005750
Partial Peak	0.00%	NA	0		$0.000000
Off-Peak	0.00%	4,157	0.00000036		$0.000012
Super Off-Peak	N/A	460	0		$0.000000
	21.41%	5,832			
Without Time-of-Delivery Metering ($16.62/kW-Year)					
Summer	78.59%	2,928	0.00026841	0.989	$0.004412
Winter	21.41%	5,832	0.00003671		$0.000603

Table 8. Illustrative SCE As-Available Capacity Prices

	Capacity Allocation Factor	Hours	Capacity Adjustment Factor (year/hour)	Capacity Loss Adjustment Factor (Transmission)	As-Delivered Capacity Price, Transmission ($/kWh)
Summer (Jun – Sept) - $33.24/kW-Year					
On-Peak	71.68%	420	0.0017067		$0.0567
Mid-Peak	12.40%	190	0.0006526		$0.0217
Off-Peak	0.24%	2,318	0.0000010		$0.0000
Super Off-Peak	NA	NA	0		
	84.32%	2,928			
Winter (Jan – May and Oct – Dec) - $33.24/kW-Year					
On-Peak	NA	NA			
Mid-Peak	14.24%	1,215	0.0001172		$0.0039
Off-Peak	0.88%	2,673	0.0000033		$0.0001
Super Off-Peak	0.56%	1,944	0.0000029		$0.0001
	15.68%	5,832			
Without Time-of-Delivery Metering ($16.62/kW-Year)					
Summer	84.32%	2,928	0.0002880		$0.0048
Winter	15.68%	5,832	0.0000269		$0.0004

Table 9. Illustrative SDG&E As-Available Capacity Prices

	Capacity Allocation Factor	Hours	Capacity Adjustment Factor (year/hour)	Capacity Loss Adjustment Factor	As-Delivered Capacity Price, Transmission ($/kWh)
Summer (May – Sept) - $33.24/kW-Year					
Peak	72.79%	765	0.000951467		$0.031627
Semi-Peak	NA	0	0		$0.000000
Off-Peak	5.86%	1,613	0.00003635		$0.001208
Super Off-Peak	NA	1,294	0		$0.000000
	78.65%	3,672			
Winter (Jan – Apr and Oct – Dec) - $33.24/kW-Year					
Peak	5.84%	1,060	0.00005507		$0.001831
Semi-Peak	NA	0	0		$0.000000
Off-Peak	15.51%	2,056	0.00007545		$0.002508
Super Off-Peak	N/A	1,972	0		$0.000000
	21.35%	5,088			
Without Time-of-Delivery Metering ($16.62 /kW-Year)					
Summer	78.65%	3,672	0.00021419		$0.003560
Winter	21.35%	5,088	0.0000420		$0.000697

Staff Time of Execution Energy Proposal

To establish an avoided cost price for energy priced at the time of contract execution, Staff proposes to use an average of CAISO default load aggregation point (DLAP) prices over the past three years, as shown in Table 13, below. This price would be available for the duration of the contract term, but would be updated annually for new standard offer contracts.

Table 10. CAISO Day-Ahead Prices ($/kWh), at the Default Load Aggregation Point or DLAP, 2015 – 2017

	2015	2016	2017	Average, 2015 - 2017
PG&E DLAP	0.03407	0.02986	0.03479	0.03290
SCE DLAP	0.03259	0.02905	0.03521	0.03228
SDG&E DLAP	0.03337	0.03045	0.03616	0.03332

By way of comparison, short-run avoided costs for the PG&E, SCE and SDG&E for the past three years, and the three-year average, are shown in Table 14 below.

Table 11. Annual Average SRAC Prices ($/kWh), 2015 – 2017

	2015	2016	2017	Average, 2015 - 2017
PG&E	0.03184	0.02599	0.0318	0.02988
SCE	0.03118	0.02478	0.03101	0.02899
SDG&E	0.03118	0.02482	0.03096	0.02899

To allocate the average DLAP prices to updated time-of-use periods (from recent Commission decisions, proposed decisions, and settlement proposals), Staff proposes to use the TOU factors based on prices for the last three years, as shown in Table 15 below. That is, Staff took the ratio of prices over the past three years in each of the TOU period to average prices to calculate the TOU factors. Staff notes that it might make sense to use allocation factors only from the previous year, which might better reflect pricing trends, but have used a three-year trend here, to capture long-term trends, rather than these short-term fluctuations.

Staff calculated revised TOU factors as a ratio of default load aggregation point (DLAP) prices in PG&E, SCE, and SDG&E in each of these time periods over the last three years to average prices in the last three years. The revised time-periods and TOU factors for the three IOUs are shown in the tables below.

Table 12. Proposed PG&E Energy Only Time-of-Use Periods for SRAC Energy Prices and TOU Factors

	Summer Jun 1 – Sep 30	Winter Oct 1 – May 30	Applicable Days
Peak	4:00 pm – 9:00 pm	4:00 pm – 9:00 pm	All Days
TOU Factor	1.6956	1.3053	
Partial-Peak	2:00 pm – 4:00 pm 9:00 pm – 11:00 pm	NA	All Days All Days
TOU Factor	1.2239	NA	
Off-Peak	11:00 pm –Midnight Midnight - 2:00 pm	9:00 pm – Midnight Midnight – 9:00 am 9:00 am – 2:00 pm, Oct - Feb 2:00 pm – 4:00 pm	All Days All Days All Days All Days
TOU Factor	0.9233	0.8625	
Super Off-Peak	NA	9:00 am – 2:00 pm, Mar - May	All Days
TOU Factor	NA	0.5817	

Table 13. Proposed SCE Energy Only Time-of-Use Periods for SRAC Energy Prices and TOU Factors

	Summer **June 1 – Sept 30**	**Winter** **Oct 1 – May 31**	**Applicable Days**
On-Peak	4:00 pm – 9:00 pm	NA	Weekdays except Holidays
TOU Factor	1.7954	NA	
Mid-Peak	4:00 pm – 9:00 pm	4:00 pm – 9:00 pm	All Days Weekends (and Holidays)
TOU Factor	1.4943	1.3564	
Off-Peak	9:00 pm – 4:00 pm	9:00 pm – 8:00 am	All Days
TOU Factor	0.9798	0.9088	
Super Off-Peak	NA	8:00 am – 4:00 pm	All Days
TOU Factor	NA	0.7050	

Table 14. Proposed SDG&E Energy Only Time-of-Use Periods for SRAC Energy Prices and TOU Factors

	Summer **Jun 1 – Oct 31**	**Winter** **Nov 1 – May 31**	**Applicable Days**
Peak	4:00 pm – 9:00 pm	4:00 pm – 9:00 pm	All Days
TOU Factor	1.7089	1.3446	
Off-Peak	6:00 am – 4:00 pm 9:00 pm – Midnight 2:00 pm – 4:00 pm 9:00 p.m. - Midnight	6:00 am – 4:00 pm (except 10 am – 2 pm in Mar & Apr) 9 pm - Midnight 2:00 pm – 4:00 pm 9:00 p.m. – Midnight	Weekdays except Holidays Weekdays except Holidays Weekends and Holidays Weekends and Holidays
TOU Factor	1.0862	0.9385	
Super Off-Peak	Midnight – 6:00 am Midnight – 2:00 pm	Midnight – 6:00 am 10:00 am – 2:00 pm (in Mar & Apr) Midnight – 2:00 pm	Weekdays except Holidays Weekdays except Holidays Weekends and Holidays
TOU Factor	0.8530	0.6993	

Staff notes that CAISO prices have remained fairly stable over the past three years and have not exhibited a clear upward or downward trend. In addition, these prices appear to be consistent with long-term contracts that have been executed recently for renewable energy. Finally, from a more macro perspective, there are pricing pressures that apply in both directions – that is, increasing penetration of renewables could exert downward pressure on prices (as they have done during mid-day periods over the past several years) and fluctuations in gas prices and supply and demand balances could exert either upward or downward pressure on prices over the coming decade.

Staff Time of Execution As-Available Capacity Proposal

To establish an avoided cost price for as-available capacity at the time of contract execution, Staff proposes to use either (1) the as-available capacity prices currently available in the existing Standard

Contract for QFs 20 MW or Less, with a pre-specified escalation factor of 2.5 percent, and to allocate these capacity costs to revised season and TOU definitions adopted or proposed by the Commission and settling parties or (2) an average of publicly available RA prices at the time of execution.

Potential capacity prices under the time of execution pricing option are shown in the following table:

Table 15: Future As-Available Capacity Prices at Time of Execution

Year	Total Marginal CT Cost ($/kW-yr)	Ancillary Services ($/kW-yr)	Energy Benefits ($/kW-yr)	As-Available Capacity Price ($
2018	$86.93	$14.82	$16.78	$55.33
2019	$89.16	$14.82	$16.78	$57.56
2020	$91.43	$14.82	$16.78	$59.83
2021	$93.77	$14.82	$16.78	$62.17
2022	$96.17	$14.82	$16.78	$64.57
2023	$98.62	$14.82	$16.78	$67.02
2024	$101.13	$14.82	$16.78	$69.53
2025	$103.71	$14.82	$16.78	$72.11
2026	$106.36	$14.82	$16.78	$74.76
2027	$109.06	$14.82	$16.78	$77.46
2028	$111.84	$14.82	$16.78	$80.24

In addition, Staff proposes to use the capacity allocation factors at the time of execution and to apply these factors to the updated time-of-use periods, based on the last Commission approved capacity allocation factors and time-of-use periods. The table below shows illustrative capacity allocation factors, which allocate capacity primarily to the 4 pm to 9 pm period during the summer periods for all three IOUs, which is consistent with the CAISO's current availability assessment hours, which are 4 pm to 9 pm, daily. This table applies the capacity allocation factors to the hours in each time-period for 2018, but these would need to updated on a yearly basis, or could remain static if necessary, for this type of contract.

Table 16: **Illustrative As-Available Capacity Allocation Factors for Time-of-Execution Contracts**

	PG&E		SCE		SDG&E	
	Capacity Allocation Factor	**Hours**	**Capacity Allocation Factor**	**Hours**	**Capacity Allocation Factor**	**Hours**
Summer Period	Jun-Sep		Jun – Sep		Jun – Oct	
Peak	76.19%	610	71.68%	420	72.79%	765
Partial/Mid/Semi-Peak	2.38%	488	12.40%	190	NA	NA
Off-Peak	0.02%	1,830	0.24%	2,318	5.86%	1,613
Super Off-Peak	NA	NA	NA	NA	NA	1,294
Total	***78.59%***	***2,928***	***84.32%***	***2,928***	***78.65%***	***3,672***
Winter	Oct - May		Oct – May		Nov - May	
Peak	21.25%	1,215	NA	NA	5.84%	1,060
Partial/Mid/Semi-Peak	NA	NA	14.24%	1,215	NA	NA
Off-Peak	0.15%	4,157	0.88%	2,673	15.51%	2,056
Super Off-Peak	0%	460	0.56%	1,944	NA	1,972
Total	***21.41%***	***5,832***	***15.68%***	***5,832***	***21.35%***	***5,088***
w/o Time of Delivery						
Summer	78.59%	2,928	84.32%	2,928	78.65%	3,672
Winter	21.41%	5,832	15.68%	5,832	21.35%	5,088
Total	***100.00%***	***8,760***	***100.00%***	***8,760***	***100%***	***8,760***

Appendix A: Short-Run Avoided Cost Energy and As-Available Capacity Prices – June 2018

The June 2018 short run avoided costs of energy and as-available capacity paid by PG&E, SCE and SDG&E to generators under the Standard Contract for QFs 20 MW or Less are shown in the figures below.

Figure 7. PG&E Short Run Avoided Cost Energy Prices for QF Facilities, June 2018

Pacific Gas and Electric Company

SHORT RUN AVOIDED COST ("SRAC")
ENERGY PRICES FOR QUALIFYING FACILITIES AND
COMBINED HEAT & POWER FACILITIES

EFFECTIVE June 1 - 30, 2018
Submitted 06/11/2018
Prepared pursuant to Decision D.10-12-035 and Resolution E-4246

June-18	Energy Prices ($/kWh)	Winter	Summer
Energy price (EP) in $/kWh is calculated based on substituting the variables below into the formula adopted in D.10-12-035:	**Peak**	**-**	**0.034648**
	Partial-Peak	**-**	**0.040551**
EP = [(Market Heat Rate * BTGP / 10^6) + VOM] * TOU	**Off-Peak**	**-**	**0.035275**
	Super Off-Peak	**-**	**0.020558**
*These energy prices do not include applicable **Locational Adjustments (LA)** under D.10-12-035.*	**Monthly Weighted Average**	**-**	**0.033790**

Market Heat Rate (MHR) =	12-month forward market heat rate per CPUC D.07-09-040 and Res. E-4246					
	Calendar Year(s)	Heat Rate				
	2016 and beyond (after Floor Test Term)	MHR	Btu/kWh			
				Market Heat Rate	**7,455**	**Btu/kWh**

BTGP	**= GPn + GTn**	(Calendar month Burner Tip Gas Price), where					
	GPn =	Simple average of natural gas bidweek price indices for Malin and Topock from Gas Daily, Natural Gas Intelligence and Natural Gas Week	Malin Topock	2.0900 2.3200	$/MMBtu $/MMBtu		
					Average Bidweek Gas Price	**2.2050**	**$/MMBtu**
	GTn =	Intrastate Transportation					
		G-AAOFF - Redwood	PG&E AL 3919-G			0.5409	$/MMBtu
		G-AAOFF - Baja	PG&E AL 3919-G			0.5889	$/MMBtu

Gas Rule 21 Shrinkage	PG&E AL 3883-G, Backbone	Shrinkage	1.2%	0.0268	$/MMBtu
Backbone Transport	Average Redwood, Baja plus shrinkage			0.5917	$/MMBtu
G-EG	PG&E AL 3919-G, Non-Backbone			1.2770	$/MMBtu
G-SUR	PG&E AL 3979-G			0.0121	$/MMBtu
			Total Intrastate Transportation	**1.8808**	**$/MMBtu**
			Monthly Burner Tip Gas Price	**4.0858**	**$/MMBtu**

VOM	=	Calendar month avoided variable O&M	0.003332	**$/kWh**

TOU	=	Energy-only Time-of-Use factors	**Winter**	**Summer**
		Peak =		1.0254
		Partial-Peak =		1.2001
		Off-Peak =		1.0440
		Super Off-Peak =		0.6084

SEASON AND TIME PERIOD DEFINITIONS

Time Period	Period A - Summer May 1 - October 31	Period B - Winter November 1 - April 30	Applicable Days	# of Hours June-18 Winter	# of Hours June-18 Summer
Peak	Noon - 6:00 p.m.	NA	Weekdays except Holidays		126
Partial-Peak	8:30 a.m. - Noon	8:30 a.m. - 9:30 p.m.	Weekdays except Holidays		147
	6:00 p.m. - 9:30 p.m.		Weekdays except Holidays		
Off-Peak	9:30 p.m. - 1:00 a.m.	9:30 p.m. - 1:00 a.m.	Weekdays except Holidays		327
	5:00 a.m. - 8:30 a.m.	5:00 a.m. - 8:30 a.m.	Weekdays except Holidays		
	5:00 a.m. - 1:00 a.m.	5:00 a.m. - 1:00 a.m.	Weekends & Holidays		
Super Off-Peak	1:00 a.m. - 5:00 a.m.	1:00 a.m. - 5:00 a.m.	All Days		120
			Total		720

2018 Holidays: New Year's Day (1/1), Presidents' Day (2/19), Memorial Day (5/28), Independence Day (7/4), Labor Day (9/3), Veterans Day (11/11), Thanksgiving Day (11/22) and Christmas Day (12/25). When any holiday listed above falls on Sunday, the following Monday will be recognized as a holiday. No change will be made for holidays falling on Saturday.

NOTE: PG&E reserves all of its available rights and remedies to revise this posting retroactive to June 1, 2018.
PG&E's Energy Prices for QFs are available on PG&E's website at: www.pge.com/qf.
Please direct questions regarding this posting to QFGeneralInquiries@pge.com.

Figure 8. PG&E Capacity Prices for Qualifying Facilities, June 2018

Pacific Gas and Electric Company

2018 AS-DELIVERED CAPACITY PRICES FOR QUALIFYING FACILITIES

Effective January 1, 2018 [1]

	Capacity [2] Value $/kw-year	Capacity Allocation Factor [3] year/hr	Capacity Loss Adjustment Factor [4] Transmission	Capacity Loss Adjustment Factor [4] Primary & Secondary Distribution	As-Delivered Capacity Price [5] Transmission $/kwh	As-Delivered Capacity Price [5] Primary & Secondary Distribution $/kwh
	(a)	(b)	(c)	(d)	(e) = a * b * c	(f) = a * b * d
With Time-of-Delivery Metering						
Period A - Summer (May through October)						
Peak	55.330	0.0009844	0.989	0.991	**0.053868**	**0.053977**
Partial-Peak	55.330	0.0000264	0.989	0.991	**0.001445**	**0.001448**
Off-Peak	55.330	0.0000001	0.989	0.991	**0.000005**	**0.000005**
Super Off-Peak	55.330	0.0000000	0.989	0.991	**0.000000**	**0.000000**
Period B - Winter (January through April, November and December)						
Partial-Peak	55.330	0.0001318	0.989	0.991	**0.007212**	**0.007227**
Off-Peak	55.330	0.0000007	0.989	0.991	**0.000038**	**0.000038**
Super Off-Peak	55.330	0.0000000	0.989	0.991	**0.000000**	**0.000000**
Without Time-of-Delivery Metering						
Period A	27.665	0.0001780	0.989	0.991	**0.004870**	**0.004880**
Period B	27.665	0.0000493	0.989	0.991	**0.001349**	**0.001352**

1. Interested parties are hereby notified that PG&E reserves all its available rights and remedies to obtain a revision to this posting effective as of January 1, 2018.

2. The as-delivered capacity value is derived in accordance with CPUC Decision No. 07-09-040 COL 36, adopting a Combustion Turbine (CT) cost proposed by TURN in its Exhibit 149, less adjustments for ancillary services and energy benefits. The 2018 CT cost is $86.93/kW-year and is adjusted annually, as detailed in TURN's Exhibit 149, Appendix B. A weighted average of the capacity value is used for meters without time-of-delivery metering.

3. Capacity allocation factors (CAF) allocate the capacity value for seasons and time-of-delivery periods. These factors are derived by dividing the allocation percentages effective January 1, 2018, and approved in D. 97-03-017 by the number of hours in each time-of-delivery period. These percentages and hours are summarized, as follows:

	CAFs (%) Period A	CAFs (%) Period B	2018 Delivery Hours Period A	2018 Delivery Hours Period B
Peak	76.19%	N/A	774	0
Partial-Peak	2.38%	21.25%	903	1,612
Off-Peak	0.02%	0.15%	2,003	2,008
Super-Off-Peak	N/A	N/A	736	724
Season total	78.59%	21.41%	4,416	4,344

Example of year/hr CAF for "Period A - Peak:"
76.19% divided by 768 hours = 0.0009921

4. Capacity prices are adjusted for the effect of deliveries on PG&E's transmission and distribution losses based upon the seller's interconnection voltage level. The loss adjustment factors for non-remote facilities (as defined by the CPUC) are shown here.

5. The as-delivered capacity price is the product of three factors: capacity value, allocation factor, and capacity loss adjustment factor.

Figure 9. SCE Short Run Avoided Cost Energy Prices for QF Facilities, June 2018

SHORT RUN AVOIDED COST
ENERGY PRICE UPDATE
FOR QUALIFYING FACILITIES
Pursuant to D.10-12-035
June 1, 2018 - June 30, 2018

SRAC Formula

Pn (cents/kWh) = [Market HR x BTGP/ 10,000 + VOM] x TOU + LA

BTGP = GPn + GTn

Energy Price by Time Period (cents/kWh) *	Summer
On-Peak	4.9188
Mid-Peak	3.5637
Off-Peak	2.9428
Super-Off-Peak	-
Time Period Weighted Average	3.4516

* These energy prices exclude LA

Pn	=	Energy price in cents/kWh which is calculated based on substituting the variables below into the formula.				
GPn	=	The simple average of natural gas market price indices from Natural Gas Week, Natural Gas Intelligence and Platts Gas Daily at the Southern California Border.				
				SoCal Border		
			Simple Average	2.3200	2.3200	$/MMBtu
GTn	=	Intrastate Transportation			0.5097	$/MMBtu
		GT-TLS		0.20300		
		G-BTS1		0.26353		
			In-Kind Energy Charges (0.083 %)	0.00193		
		G-MSUR	0.014136 * 0.985864 * 2.9562	0.04120		
Market Heat Rate				11,020	11,020	Btu/kWh
VOM	=	Variable Operations and Maintenance adder			0.3332	cents/kWh
TOU Factor	=	Summer On-Peak			1.4251	
		Summer Mid-Peak = (Total # hrs in month -				
		(1.4251 * # Summer On-Peak hrs in month) -				
		(0.8526 * # Summer Off-Peak hrs in month)) /			1.0325	
		# Summer Mid-Peak hrs in month				
		Summer Off-Peak			0.8526	
		Winter Mid-Peak			1.2185	
		Winter Off-Peak = (Total # hrs in month -				
		(1.2185 * # Winter Mid-Peak hrs in month) -				
		(0.7760 * # Winter Super-Off-Peak hrs in month)) /				
		# Winter Off-Peak hrs in month				
		Winter Super-Off-Peak			0.7760	

SEASON AND TIME PERIOD DEFINITIONS

				6/1/18 - 6/30/18	
	Summer	Winter		# of Hours	
Time Period	June 1 - September 30	October 1 - May 31		Winter	Summer
On-Peak	Noon - 6:00 p.m.	n/a	Weekdays except Holidays	0	126
Mid-Peak	8:00 a.m. - Noon	8:00 a.m. - 9:00 p.m.	Weekdays except Holidays	0	84
	6:00 p.m. - 11:00 p.m.		Weekdays except Holidays	0	105
Off-Peak	11:00 p.m. - 8:00 a.m.	6:00 a.m. - 8:00 a.m.	Weekdays except Holidays	0	189
		9:00 p.m. - Midnight	Weekdays except Holidays	0	0
	Midnight - Midnight	6:00 a.m. - Midnight	Weekends & Holidays	0	216
Super-Off-Peak	n/a	Midnight - 6:00 a.m.	Weekdays, Weekends & Holidays	0	0
			Total	0	720

2018 Holidays: New Year's Day (1/1), Presidents' Day (2/19), Memorial Day (5/28), Independence Day (7/4), Labor Day (9/3), Veterans Day (11/11), Thanksgiving Day (11/22) and Christmas Day (12/25). When any holiday listed above falls on Sunday, the following Monday will be recognized as an off-peak period. No change will be made for holidays falling on Saturday

Figure 10. SCE Capacity Prices for Qualifying Facilities, June 2018

SHORT RUN AVOIDED COST ENERGY PRICE UPDATE
FOR QUALIFYING FACILITIES
Issued June 11, 2018
Effective June 1, 2018 - June 30, 2018

Following are the capacity and energy price schedules for purchases from Qualifying Facilities pursuant to Standard Offers and other contracts with Southern California Edison Company, effective June 1, 2018 - June 30, 2018

This posting is made in compliance with the formula adopted by the Commission on December 16, 2010 in Decision No. 10-12-035.

GENERAL INFORMATION

If you have any questions, please direct your inquiries to Southern California Edison Company, Renewable and Alternative Power, P.O. Box 800, Rosemead, CA 91770.
SCE's SRAC Posting may be viewed electronically at SCE's home page http://www.sce.com/AboutSCE/Regulatory/qualifyingfacilities/dataanddocuments.htm.

AVOIDED COST CAPACITY PRICES FOR QUALIFYING FACILITIES

Pursuant to California Public Utilities Commission ("CPUC") Decision Nos. 10-12-035 and 07-09-040, the as-available capacity price for 2018 is $55.33 / kW-year.
Per D.82-01-103, capacity payments are reduced 50% for projects under Standard Offer No. 3 with no time of delivery meters.

CAPACITY PAYMENT SCHEDULE FOR AS-AVAILABLE POWER PURCHASES

Time Differentiated Payments		Non-Time Differentiated Payments	
Costing Period	Capacity Payments (cents/kWh)		(cents/kWh)
Summer: On-Peak	7.87	Summer	0.80
Mid-Peak	0.91		
Off-Peak	0.01		
Winter : Mid-Peak	0.36	Winter	0.07
Off-Peak	0.02		
Super-Off-Peak	0.02		

MONTHLY CONVERSION FACTORS

The factors to convert annual capacity prices ($/kW-year) to time period of delivery prices are as follows:

	On-Peak	Mid-Peak	Off-Peak	Super-Off-Peak
Summer	0.1792	0.0310	0.0006	-
Winter	-	0.0178	0.0011	0.0007

Figure 11. SDG&E Short Run Avoided Cost Energy Prices for QF Facilities, June 2018

San Diego Gas & Electric Company
ENERGY PRICE UPDATE
FOR QUALIFYING FACILITIES
Pursuant to D.07-09-040, D.10-12-035, D.11-07-010, D.11-10-016 and Resolution E-4246
Effective: June 1, 2018 - June 30, 2018

Energy Price Formula : Pn = [Market HR x BTGP/ 10,000 + O&M] x TOU + LA
BTGP = GPn + GTn

	SRAC	
	Winter	**Summer**
On-Peak	-	4.8918
Semi-Peak	-	3.8344
Off-Peak	-	3.4184
Super-Off-Peak	-	2.2361
Time Period Weighted Average	-	3.5821

Note: These published energy prices exclude hourly location adjustments (LA).

Pn	=	Energy price in cents/kWh which is calculated based on substituting the variables below into the formula.			
GPn	=	The simple average of natural gas market price indices from Natural Gas Intelligence, Platts Gas Daily and Natural Gas Week at the Southern California Border.			
			SoCal Border		
		Simple Average	2.3200	2.3200	$/MMBtu
GTn	=	Intrastate Transportation			
		GT-TLS *	0.2017		
		G-BTS1 **	0.2635		
		In-Kind Energy Charges (0.083%)	0.0019		
		GP-SUR	0.0480	0.5152	$/MMBtu
		Market Heat Rate ***		11,053	Btu/kWh
O&M	=	Variable Operations and Maintenance adder	6/1/2018	0.3332	cents/kWh
TOU	=	Summer On-Peak		1.4110	
		Summer Semi-Peak		1.1060	
		Summer Off-Peak		0.9860	
		Summer Super-Off-Peak		0.6450	
		Winter On-Peak		1.2240	
		Winter Semi-Peak		1.1060	
		Winter Off-Peak		0.9330	
		Winter Super-Off-Peak		0.7110	

SEASON AND TIME PERIOD DEFINITIONS

Time Period		Summer MAY 1 - SEPTEMBER 30	Winter OCTOBER 1 - APRIL 30			# of Hours Effective: June 1, 2018 - June 30, 2018 Winter	 Summer
ON-PEAK		11:00 a.m. - 6:00 p.m.	5:00 p.m. - 8:00 p.m.	Weekdays		0	147
SEMI-PEAK		6:00 a.m. - 11:00 a.m.	6:00 a.m. - 5:00 p.m.	Weekdays		0	189
		6:00 p.m. - 10:00 p.m.	8:00 p.m. - 10:00 p.m.	Weekdays			
OFF-PEAK		10:00p.m. - 12:00 mid.	10:00 p.m. - 12:00 mid.	Weekdays		0	234
		5:00 a.m. - 6:00 a.m.	5:00 a.m. - 6:00 a.m.	Weekdays			
		5:00 a.m. - 12:00 mid.	5:00 a.m. - 12:00 mid.	Weekends			
		5:00 a.m. - 12:00 mid.	5:00 a.m. - 12:00 mid.	Holidays			
Super Off-Peak		12:00 mid. - 5:00 a.m.	12:00 mid. - 5:00 a.m.	All Days		0	150
					Total	0	720

2018 Holidays: New Year's Day (1/1), Presidents' Day (2/19), Memorial Day (5/28), Independence Day (7/4), Labor Day (9/3), Veterans Day (11/12), Thanksgiving Day (11/22) and Christmas Day (12/25). When any holiday listed above falls on Sunday, the following Monday will be recognized as an off-peak period. No change will be made for holidays falling on Saturday.

* Effective February 1, 2010, the gas transportation tariff EG was changed to apply to distribution service level gas customers only. The transmission service level gas customers are now covered under the TLS tariff, published at http://www.sdge.com/tm2/pdf/GAS_GAS-SCHEDS_TLS.pdf. Beginning with the February 2010 SRAC posting, SDG&E replaced EG rate with TLS rate in the SRAC calculation.

** Effective October 1, 2011, the gas transportation tariff RPA was changed to apply to firm and interruptible Backbone Transportation Service (BTS) to Utility's transmission system. The Backbone Transportation Service gas customers are now covered under the BTS tariff, published at http://www.socalgas.com/regulatory/tariffs/tm2pdf/G-BTS.pdf. Beginning with the October 2011 SRAC posting, SDG&E replaced RPA rate with BTS rate in the SRAC calculation.

***Effective January 1, 2016, only the Market Heat Rate is included in the SRAC calculation, eliminating the option for the Actual Heat Rate.

***Effective February 1, 2017, the Market Heat Rate calculation uses ICE for the SoCal Basis forward prices. The NYMEX SoCal Basis forward curve is no longer available.

Figure 12. SDG&E Capacity Prices for Qualifying Facilities, June 2018

SHORT RUN AVOIDED COST ENERGY PRICE UPDATE
FOR QUALIFYING FACILITIES
Filed: June 8, 2018
Effective: June 1, 2018 - June 30, 2018

Following are the capacity and energy price schedules for purchases from Qualifying Facilities pursuant to Standard Offers and other contracts with San Diego Gas & Electric Company ("SDG&E"), for the above mentioned effective period.

This posting is made in compliance with the revised formula adopted by the Commission on September 20, 2007 in Decision No. 07-09-040 and clarified by Resolution E-4246 dated July 9, 2009, and the QF/CHP Settlement Agreement which take effect on November 23, 2011 pursuant to Decision No. 10-12-035, 11-07-010 and 11-10-016.

GENERAL INFORMATION

If you have any questions, please direct your inquiries to San Diego Gas & Electric Company, Electric & Fuel Procurement, 8315 Century Park Court, CP 21D, San Diego, CA 92123. SDG&E's SRAC Posting may be viewed electronically at SDG&E's home page: http://www2.sdge.com/qfi

AVOIDED COST CAPACITY PRICES FOR QUALIFYING FACILITIES

Pursuant to California Public Utilities Commission ("CPUC") Decision No. 07-09-040, the as-available capacity price for 2018 is $55.33 / kW-year.
Per D.82-01-103, capacity payments are reduced 50% for projects under Standard Offer No. 3 with no time of delivery meters.

AS-AVAILABLE CAPACITY PRICE CALCULATIONS *	(¢/kWh):	ON-PEAK	SEMI-PEAK	OFF-PEAK	SUPER OFF-PEAK	NON-TOU **
CAPACITY PRICES	SUMMER	5.4277	0.3401	0.0000	0.0000	0.5926
	WINTER	0.7324	0.4492	0.0000	0.0000	0.1155
	VOLTAGE LEVEL ADJUSTMENTS					
TRANSMISSION LEVEL	SUMMER	5.5970	0.3501	0.0000	0.0000	0.6076
	WINTER	0.7548	0.4618	0.0000	0.0000	0.1184
PRIMARY LEVEL	SUMMER	5.8353	0.3643	0.0000	0.0000	0.6287
	WINTER	0.7862	0.4794	0.0000	0.0000	0.1224
	ALLOCATION FACTORS					
CAPACITY ALLOCATION FACTORS	SUMMER	0.098096	0.006146	0.00000	0.00000	0.010709
	WINTER	0.013237	0.008118	0.00000	0.00000	0.002088
	LINE LOSS FACTORS					
TRANSMISSION LEVEL	SUMMER	1.0312	1.0296	1.0213	1.0213	1.0255
	WINTER	1.0306	1.0281	1.0214	1.0214	1.0247
PRIMARY LEVEL	SUMMER	1.0751	1.0712	1.0509	1.0509	1.0611
	WINTER	1.0734	1.0674	1.0511	1.0511	1.0592

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***AS-AVAILABLE CAPACITY PRICES = YEARLY CAPACITY VALUE x ALLOCATION FACTORS x LINE LOSS FACTORS**

****50% OF WEIGHTED AVERAGE FOR TOU PERIODS**