PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

FILED
07/05/18
10:16 AM

July 5, 2018

Agenda ID #16654
Ratesetting

TO PARTIES OF RECORD IN APPLICATION 16-06-013:

This is the proposed decision of Administrative Law Judge Doherty. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's August 9, 2018 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, ex parte communications are prohibited pursuant to Rule 8.3(c)(4)(B).

/s/ MICHELLE COOKE for
Anne E. Simon
Chief Administrative Law Judge

AES:ek4

Attachment

Decision **PROPOSED DECISION OF ALJ DOHERTY (Mailed 7/5/2018)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Revise its Electric Marginal Costs, Revenue Allocation and Rate Design. (U39M)	Application 16-06-013

DECISION ON PACIFIC GAS AND ELECTRIC COMPANY'S PROPOSED RATE DESIGNS AND RELATED ISSUES

Table of Contents

Title **Page**

Table of Contents (cont.)

Title **Page**

Table of Contents (cont.)

Table of Contents (cont.)

PROPOSED DECISION ON PACIFIC GAS AND ELECTRIC COMPANY'S PROPOSED RATE DESIGNS AND RELATED ISSUES

Summary

This decision resolves the application of Pacific Gas and Electric Company (PG&E) to revise its electric marginal cost allocations and retail rate designs for its various customer classes, and other related issues. For the most part, this decision accepts settlements among the parties to this proceeding that make significant changes to PG&E's rate designs. These changes include creating a 4 p.m. to 9 p.m. peak period for most non-residential customers and a 5 p.m. to 8 p.m. peak period for agricultural customers, creating a super off-peak period in the spring to increase utilization of renewable energy generation resources, and shrinking PG&E's summer season to a four month period of June through September.

However, this decision proposes modifications to certain elements of the settlement related to rate designs for medium and large commercial customers, as the settlement's terms on these elements are unreasonable in light of the proceeding's record and previous California Public Utilities Commission decisions. The proposed modifications concern the cost basis for the distribution demand charges proposed by that settlement. We propose a revised cost basis and attendant rate design for those demand charges.

This decision also describes our general concern with PG&E's approach to rate design in this proceeding, and mandates elements that PG&E's future rate design applications must include.

This decision resolves disputed areas of fact and law where the parties could not reach agreement. We reject the proposal for a particular rate design for former E-37 customers, the proposal to revise revenue allocations for the

agricultural class, and the proposals for alternative methodologies for calculating the master meter discount. We do find that it is reasonable to apply a particular rate design to Renewable Energy Self-Generation Bill Credit Transfer customers, to create an "Option S" rate for certain energy storage customers, and to address sales forecasting errors that frequently afflict the agricultural customer class.

1. Procedural Background

On June 30, 2016, Pacific Gas and Electric Company (PG&E) filed an application to revise its electric marginal costs, revenue allocation, and retail rate designs for its various customer classes. In essence, the application sought to revise the amount of PG&E's forecasted costs that each customer class is responsible for, and the retail rates used to recover that amount from each customer class.

Protests to PG&E's application were filed by the Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), South San Joaquin Irrigation District (SSJID), jointly by Merced Irrigation District and Modesto Irrigation District (MMID), jointly by Agricultural Energy Consumers Association (AECA) and California Farm Bureau Federation (CFBF), Solar Energy Industries Association (SEIA), The Alliance for Solar Choice (TASC), California Independent Petroleum Association (CIPA), and the Western Manufactured Housing Communities Association (WMA). A number of other parties filed motions for party status.

On September 12, 2016, a prehearing conference (PHC) was held to determine parties, discuss the scope, the schedule, and other procedural matters. All organizations that filed motions for party status or that appeared at the PHC requesting party status were granted such status.

A scoping memo in this proceeding was filed on October 19, 2016, and established the following issues as within the scope:

1. Are PG&E's marginal cost proposals reasonable and should they be adopted?
2. Are PG&E's proposed updated service fees for Direct Access (DA) and Community Choice Aggregation (CCA) customers, filed in compliance with Commission Decision (D.) 13-04-020, reasonable and should they be adopted?
3. Is PG&E's proposed methodology for a potential future residential fixed charge reasonable, and should it be adopted?
4. Is PG&E's proposed Revenue Requirement increase of approximately $510,000 for recovery of certain costs incurred to develop a real time pricing proposal (as D.08-07-045 required PG&E to include in a rate proceeding) reasonable, and should it be adopted?
5. Are the Time-of-Use (TOU) hours proposed for non-residential customers reasonable and should they be adopted?
6. Is PG&E's proposal for a four month summer season and an eight month winter season reasonable and should it be adopted?
7. Are PG&E's revenue allocation proposals reasonable and should they be adopted?
8. Are PG&E's rate design proposals reasonable and should they be adopted?
9. Are the proposed gas and electric baseline amounts reasonable and should they be adopted?
10. For PG&E, Southern California Edison (SCE) and San Diego Gas & Electric Company (SDG&E), what fixed costs would be appropriate for recovery through a residential fixed charge? What additional steps should be taken to ensure that any residential fixed charge treats small and large

customers fairly? What additional marketing, education and outreach plans are necessary and appropriate for fixed charges?

The scoping memo established separate phases of the proceeding, including an earlier phase that would consider the cost basis and methodology for setting a potential residential fixed charge. A final decision on the fixed charge issues (D.17-09-035) was issued on October 4, 2017. That phase of the proceeding is concluded and not considered in this decision. Therefore, items 3 and 10 from the scoping memo and ruling's list of scoped issues are disposed of.[1]

An additional issue, on an Energy Matinee Pricing Tariff pilot, was also bifurcated for an expedited decision that was issued on June 15, 2017 (D.17-06-004). That bifurcated issue is therefore disposed of and not considered in this decision.

The second phase of the instant proceeding, as described by the scoping memo, was to consider all other issues in PG&E's application.

PG&E served its updated testimony on December 2, 2016. ORA served its prepared testimony on February 15, 2017, on marginal cost, revenue allocation, and rate design. On March 15, 2017, the following parties served their prepared testimony: AECA, the California City-County Street Light Association (CAL-SLA), CFBF, CIPA, the California Large Energy Consumers Association and the California Manufacturers & Technology Association jointly

[1] Subsequent to that decision PG&E, ORA, and TURN came to agreement on certain other marginal cost inputs required for PG&E's residential time-of-use rate design window proceeding. These agreements are memorialized in Exhibits PG&E-24 and ORA-3. We attach those exhibits as appendices to this decision, as requested by PG&E in its opening brief, so that they may be utilized in other proceedings.

(CLECA/CMTA), the California Solar & Storage Association[2] (CALSSA), the California Tomato Processors (CTP), the Direct Access Customer Coalition (DACC), the Energy Producers and Users Coalition (EPUC), the Energy Users Forum (EUF), the Federal Executive Agencies (FEA), MMID, the Small Business Utility Advocates (SBUA), SEIA, SSJID, TURN, and WMA.[3]

Immediately after a settlement conference on March 24, 2017, PG&E filed and served a motion to suspend the procedural schedule to allow more time for settlement discussions. Administrative Law Judge (ALJ) Cooke issued an E-mail ruling on March 31, 2017, granting the parties' request for a continuance in the schedule to allow for further settlement conferences, and calling for settlement status reports to be filed on April 17, May 8, June 1, and June 22, 2017.

In the June 22, 2017 Status Report, PG&E notified ALJ Cooke that the active parties to the proceeding had reached a settlement in principle on revenue allocation, and that considerable progress had been made on a range of other rate design issues.

On June 26, 2017, ALJ Cooke granted a further continuance in the schedule to allow the parties time for additional work on settlement of the remaining issues in this proceeding. Pursuant to that ruling, PG&E filed additional settlement status reports on July 13, August 3, August 24, September 6, and September 14, 2017.

---

[2] Formerly known as the California Solar Energy Industries Association (CalSEIA). For the sake of clarity, any references in this decision and the record to CalSEIA should be read as referring to CALSSA.

[3] On April 26, 2017, the County of San Joaquin filed a motion for leave to file testimony late. On May 4, 2017, ALJ Cooke issued an E-mail ruling granting the County of San Joaquin's motion, and on May 19, 2017, the County of San Joaquin served its prepared direct testimony.

On September 18, 2017, the ALJ convened a telephonic PHC to address procedural and scheduling matters. PG&E updated the ALJ and the parties about the status of its efforts to determine the causes for anomalies in certain bill impact analyses. During the telephonic PHC, the ALJ and parties discussed the impact of the anomalies on scheduling, and whether there were issues in the case that would not be affected by these developments. The master meter discount, E-CREDIT, and the DA/CCA fees issues were identified as being able to move ahead without waiting for resolution of the bill comparisons and billing determinant anomalies. The ALJ and parties also agreed that another status report would be filed October 5, 2017. The ALJ set specific dates for these matters:

1) The next status report filing date was set for October 5, 2017;
2) The E-CREDIT and DA/CCA fee settlements were due no later than October 9, 2017; and
3) Master meter rate design rebuttal testimony was set to be served on October 30, 2017, with hearings set for December 14 to 15, 2017.

Scheduling for the other issues in this proceeding was to be addressed when the uncertainty over availability of bill impact comparisons, and other settlement discussions, was resolved.

On October 5, 2017, PG&E filed a settlement status report. In an E-mail ruling dated October 6, 2017, ALJ Cooke granted the request to file a settlement status report on October 16, 2017.

On October 9, 2017, PG&E filed the E-CREDIT and DA/CCA fees settlements. The California Public Utilities Commission (Commission or CPUC) issued a final decision on those two settlements (D.18-01-013) on

January 16, 2018. Item 2 from the scoping memo's list of scoped issues is therefore disposed of.

On October 17, 2017, a telephonic PHC was held that updated the schedule, which among other things included time for additional settlement discussions and two more status reports.

Subsequent to the October 17, 2017 PHC, several settlements on issues originally within the scope of the proceeding were made between the parties. These settlements are the primary subjects of this decision. A table of these settlements and the date the executed settlements were served on the parties appears below:

Settlement Issues	Date Served
Marginal Costs and Revenue Allocation	October 26, 2017
Economic Development Rate Design	November 16, 2017
Streetlight Rate Design	January 4, 2018
Time-of-Use Rates for Grandfathered Solar Customers	January 22, 2018
Residential Rate Design	January 24, 2018
Small Light and Power Rate Design	January 29, 2018
Standby and Medium and Large Light and Power Rate Design	January 31, 2018
Time-of-Use Rates for Grandfathered Solar Agricultural Customers	March 28, 2018
Agricultural Rate Design	March 30, 2018

On November 17, 2017, the assigned Commissioner in this proceeding issued a ruling seeking additional information and comment from the parties on the issue of electric baseline quantities for residential customers, and directing additional testimony on PG&E's proposed energy storage rate designs for residential and small commercial customers. PG&E filed a response to the ruling on January 5, 2018. PG&E, SCE, and the Center for Accessible Technology (CforAT) filed comments on PG&E's response to the ruling on January 31, 2018, and CforAT filed reply comments on February 9, 2018.

On November 27, 2017, an ALJ E-mail ruling granted an extension of the deadline to serve supplemental testimony in this proceeding to December 8, 2017. On November 29, 2017, an ALJ E-mail ruling extended the deadline for PG&E to file its 12th settlement status report to December 15, 2017.

On December 8, 2017, the following parties submitted supplemental testimony: CAL-SLA, County of San Joaquin, PG&E, and WMA.

On December 15, 2017, PG&E and the parties representing the interests of the agricultural class jointly requested an extension of the deadline for serving rebuttal testimony on agricultural rate design issues to March 7, 2018. This joint request was granted by ALJ E-mail ruling on December 22, 2017, and that ruling also set deadlines for providing the 13th and 14th settlement status reports of January 19, 2018, and February 7, 2018, respectively. An ALJ E-mail ruling of March 1, 2018, extended the deadline for rebuttal testimony on agricultural rate design issues to March 16, 2018.

Rebuttal testimony was served on January 25, 2018, by the following parties: CIPA, CALSSA, County of San Joaquin and County of Santa Clara, PG&E, and TURN.

On February 7, 2018, an ALJ E-mail ruling directed the service of supplemental testimony on issues related to the settlement on standby and medium and large light and power rate design. Supplemental testimony was duly served on February 21, 2018.

A telephonic PHC was held on February 8, 2018, to discuss outstanding procedural issues related to testimony and preparations for evidentiary hearings. Evidentiary hearings on disputed issues of fact were held on February 12, February 13, February 14, February 16, February 27, March 1, March 2, and April 10, 2018. The assigned ALJs also examined witnesses testifying on behalf of the executed settlements, with the exception of the streetlight rate design settlement, during evidentiary hearings.

Opening briefs in this proceeding were filed on March 23, 2018, and reply briefs were filed on April 6, 2018. Pursuant to an ALJ Ruling of April 12, 2018, a separate briefing schedule was established for master meter discount issues. Opening briefs on master meter discount issues were filed on April 30, 2018, and reply briefs on master meter discount issues were received on May 14, 2018.

Supplemental testimony was served on April 30, 2018 by CALSSA, and PG&E served its final exhibit, PG&E-55, on May 14, 2018.

Per the scoping memo, the submission date for this proceeding was due to occur upon the filing of reply briefs.[4] As the final reply briefs in this proceeding were filed on May 14, 2018, upon that date the record in this proceeding was considered submitted.[5] This decision disposes of all outstanding issues and motions in the proceeding.

In light of this procedural history, the following items from the scoping memo remain unresolved and are addressed by this decision:

---

[4] Scoping Memo at 8.

[5] A limited reopening of the record was provided in June 2018, for the filing of briefs by a single party.

- Are PG&E's marginal cost proposals reasonable and should they be adopted?
- Is PG&E's proposed Revenue Requirement increase of approximately $510,000 for recovery of certain costs incurred to develop a real time pricing proposal (as D.08-07-045 required PG&E to include in a rate proceeding) reasonable, and should it be adopted?
- Are the TOU hours proposed for non-residential customers reasonable and should they be adopted?
- Is PG&E's proposal for a four month summer season and an eight month winter season reasonable and should it be adopted?
- Are PG&E's revenue allocation proposals reasonable and should they be adopted?
- Are PG&E's rate design proposals reasonable and should they be adopted?
- Are the proposed gas and electric baseline amounts reasonable and should they be adopted?

2. Standard of Review for Settlements

We summarize our standard of review for settlements in this section. This standard is applied to the several settlements considered in this decision.

The Commission has long favored the settlement of disputes.[6] Article 12 of the Commission's Rules of Practice and Procedure generally concerns settlements. Pursuant to Rule 12.1(d) of the Commission's Rules of Practice and Procedure, the Commission will not approve a settlement unless it is found to be reasonable in light of the whole record, consistent with law, and in the public interest. This standard applies to settlements that are contested as well as

[6] D.17-08-030 at 9.

uncontested. Where a settlement is contested, it will be subject to more scrutiny than an uncontested settlement.

We wish to make clear that while our policy is to favor the settlement of disputes, our standard of review for settlements is designed to ensure that settlements meet some minimum standard of reasonableness in light of the law and the record of the proceeding. A settlement can be unreasonable, and we will not be persuaded to approve unreasonable settlements simply because of a general, long-standing policy to approve settlements. There are several attributes that can render a settlement unreasonable. One such attribute is the presence of significant deviations from Commission findings, policies, practices that are not adequately explained and justified in the motion for the settlement's adoption. Another such attribute is the lack of a demonstration that the settlement fully and fairly considered the interests of all affected entities – both parties and non-party entities such as affected customers. We are under no duty to approve unreasonable settlements.

3. A Recent History of Commission Approaches to Marginal Cost-Based Revenue Allocation and Rate Designs

Two of the key issues before us in this proceeding are the reasonableness of 1) PG&E's revenue allocation proposal, and 2) PG&E's proposed rate designs. To guide our evaluation of the reasonableness of these proposals, in light of the standard for review of settlements described above, we set out a brief history of our recent approach to these issues. This section should be read as applying to our entire discussion of both revenue allocation and rate design in this decision. In other words, the reader is asked to keep this historical discussion in mind when reviewing later sections of this decision, which largely adopt the settlements proposed in this proceeding.

For most of the 20th century, various approaches were utilized to determine the revenue allocation and rate design for PG&E's customers. We do not review all of those approaches here, but note that in the late 1970's the Commission began changing the basis of revenue allocation and rate design from the previous embedded cost approach to an approach based on marginal costs. The primary difference between embedded and marginal cost of service studies is the reliance on historical vs. incremental costs; whereas embedded cost studies focus on current accounting costs associated with past investments, marginal cost of service studies reflect the incremental costs of serving additional load or new customers. A drawback of the marginal cost approach is that the revenues collected by marginal cost pricing rarely matched the utilities' authorized revenue requirements. During the late 1970's and 1980's, a variety of methodologies were discussed for reconciliation of marginal cost revenues with authorized utility revenue requirements.

One possible reconciliation method was to simply collect the difference between utility revenue requirements and marginal cost revenues in fixed monthly customer charges.[7] A second possible reconciliation method would be to allocate non-marginal costs to customer classes in proportion to their energy usage. This is equivalent to charging non-marginal costs as a single "equal cents per kilowatt hour (kWh)" rate as an identical rate component applicable to all customer classes.

[7] Typically, authorized revenues exceed marginal cost revenues. More rarely, marginal cost pricing would overcollect authorized revenues and a negative customer charge, or fixed bill credit, would be needed for reconciliation.

Rather than adopt either of these approaches, the Commission chose to adopt a methodology based on "equal percent of marginal cost" (or EPMC) for revenue allocation and rate design.[8] Using an EPMC methodology, the revenue allocation for each class is determined by establishing the relative amount of marginal costs imposed by each class on the utility's system, and then scaling up that relative marginal cost responsibility until all of the remaining non-marginal revenue requirements were met.

To illustrate, consider a utility with three customer classes: A, B, and C. Imagine that the utility has a total revenue requirement of $1 million, where $400,000 of that total is made up of marginal costs and $600,000 are non-marginal costs. Class A is responsible for $200,000 of the marginal costs, Class B is responsible for $150,000 of the marginal costs, and Class C is responsible for $50,000 of the marginal costs.

Under the EPMC approach, each class's revenue allocation equals their marginal cost responsibility in dollars plus their relative marginal cost responsibility percentage multiplied by the total non-marginal costs for the utility. The table below illustrates the approach.

[8] Prior to the electric industry restructuring of the late 1990's, a single EPMC calculation was performed, encompassing generation, transmission, and distribution marginal cost revenues and reconciling to the utilities' combined authorized revenue requirement. Subsequently, transmission was removed from the mix and separate EPMC calculations were, and continue to be, performed for generation and distribution.

Class	Marginal Cost Responsibility	Percentage of Total Marginal Cost Responsibility (Previous Column / $400,000)	Non-Marginal Cost Responsibility (Previous Column * $600,000)	Total Revenue Allocation
A	$200,000	50%	$300,000	$500,000
B	$150,000	37.5%	$225,000	$375,000
C	$50,000	12.5%	$75,000	$125,000
Total	$400,000	100%	$600,000	$1,000,000

The advantages of the EPMC approach are its simplicity, transparency, and fairness. The equation illustrated above is simple and transparent, but it relies on an accurate assignment of marginal costs to each class.[9] It is fair because it assigns the non-marginal costs to each class proportionate to their marginal cost responsibility, which means that those classes that impose the greatest additional (or new) costs on the utility also bear the greatest burden for the existing utility costs. This creates an incentive for every class to avoid imposing additional (or new) costs on the utility, which in theory keeps rates for all classes as low as possible.

[9] We note that in this proceeding there was no agreement between the parties on the actual marginal costs that should be applied to each class. While we recognize such calculations are difficult, they are not impossible and therefore can form a reasonable basis for the EPMC approach.

Discussions of the merits of EPMC for revenue allocation can be found in a number of Commission decisions dating from 1996 and before.[10] We include several selected quotations from those decisions below:

> I favor this direction towards EPMC. While immediate adoption of the EPMC results in too sharp a shift in revenue allocation, in principle it has merit. Under an EPMC method, rates are initially calculated at full marginal cost. Insofar as the rates derived from the revenue requirement are different from marginal cost, the difference is allocated on an equal percentage basis among classes. Individual rates can then be designed as much as possible on marginal cost principles, within the constraints of the total revenue allocation. **This approach presents an equitable assignment of costs among the various classes based on the foundation of marginal cost principles.** Insofar as rates for classes deviate from marginal costs, they all deviate evenly.[11]
>
> As we have repeated time and time again, it is our goal to achieve fair and equitable rates through marginal cost pricing and the use of EPMC for revenue allocation.[12]
>
> By now, it should be clear that we will use EPMC for revenue allocation. [Public Staff Division's] **EPMC methodology will be adopted for inter-class and intra-class revenue allocations**.[13]
>
> [The] EPMC method for inter-class and intra-class revenue allocation, as adjusted by this decision, is a reasonable method to reflect marginal costs.[14]

---

[10] D.96-04-050 summarizes many of those decisions.

[11] D.82-12-113 at 31, concurring opinion of Commissioner John E. Bryson (emphasis added).

[12] D.86-08-083 at 26.

[13] D.86-08-083 at 28 (emphasis added).

[14] D.86-08-083, Conclusion of Law 27.

> Our decisions over the last several years have repeatedly embraced the idea of EPMC, and gradually we have adopted revenue allocations that reflect this goal. As early as 1983, we adopted EPMC for SDG&E in its general rate case (GRC) decision for test year 1984 (D.83-12-065).[15]
>
> The reasons for our embracing EPMC as a guiding principle for revenue allocation are several. First, when rates are above marginal costs, as they are currently, EPMC revenue allocation provides a fair way of relating each class's revenue requirement to the costs of providing service to that class. Second, EPMC helps reduce interclass subsidies that distort price signals and thus result in inefficiencies, to the detriment of society in general.[16]
>
> EPMC revenue allocation provides a fair way of relating each customer class's revenue requirement to the costs of providing service to that class.[17]
>
> Revenue allocation is an important step in the translation of marginal costs into rates. During interclass revenue allocation, we determine the [marginal] cost of providing services to each customer class · and derive each class' proportionate responsibility for contributing to the utility's overall revenue requirement.[18]
>
> Since marginal and ratemaking costs seldom are equal, an allocation based on marginal cost must normally be modified to produce the revenue requirement. In past decisions, we have followed the policy of moving towards an EPMC allocation. This approach allocates the revenue requirement on an equal [percentage] basis relative to the costs imposed by each rate group at the margin.[19]

---

15 D.87-05-071 at 3.

16 D.87-05-071 at 3.

17 D.87-05-071, Conclusion of Law 3.

18 D.89-12-057 at 220.

19 D.96-04-050 at 19.

> The calculation of marginal costs, and the relative responsibility for those costs among rate groups, feeds directly into the revenue allocation process. We adopt a full 'equal percentage of marginal cost' (EPMC) revenue allocation in this proceeding.[20]

The record reveals that PG&E itself supports use of EPMC for revenue allocation in this proceeding when it testified that "[t]he EPMC method makes good policy sense for distribution and generation because it provides a more equitable and economically efficient basis for the allocation of PG&E's distribution- and generation-related revenue requirements."[21]

Consistent with its use of EMPC to allocate revenue responsibility between and among customer classes, the Commission has typically used EPMC as a starting point for allocating revenue responsibility among individual customers *within* a customer class. Such allocation is the function of rate design. Using this approach, the various components of rate design (e.g., customer charges, energy charges, and demand charges) under EPMC would be set at a constant multiple of the marginal cost for those functions. Rates set in this manner have been typically termed "cost-based rates" by the Commission. For example:

> In recent years, we have pursued a goal of developing cost-based rates. When rates are fully based on costs, customers pay rates that are proportionate to the [marginal] costs the utility incurs in serving them.[22]

Expanding on the above, in D.96-04-050 the Commission stated:

> Once authorized revenues have been allocated to individual rate groups, specific prices or charges must be designed to recover that

[20] D.96-04-050 at 6.

[21] PG&E-8, Chapter 1 at 3.

[22] D.89-12-057 at 220.

> allocation. Some rate groups have rate schedules with per kWh (energy) charges only. Others have schedules that unbundle the energy charges from customer and demand charges, so that each can be designed to recover the corresponding marginal cost component. **The Commission has applied marginal cost principles to this stage of rate design as well, by establishing EPMC targets for the various charges.** As in the case of revenue allocation, however, full implementation of marginal-cost based rates has been tempered to address concerns over severe bill impacts.[23]
>
> [W]e believe that movement towards full EPMC, tempered with limits where bill impacts become unduly harsh, provides a reasonable balance between equity and efficiency in ratesetting. **We will retain our policy of similarly using EPMC as a target for setting charges within rate schedules**.[24]

Earlier Commission decisions shed additional light on use of EPMC for rate design. For example, in D.87-12-033 (citing D.86-08-083), the Commission stated:

> In PG&E's last consolidated [general rate case] the Commission endorsed the importance of EPMC for revenue allocation **and rate design**. Also, the Commission decided that **marginal cost pricing and use of EPMC as the method for implementing marginal cost pricing are the preferred way to achieve fair and equitable rates.**[25]

D.96-04-050 established EPMC as the Commission's preferred starting point for cost-based rate design and was one of the final Commission decisions to fully litigate marginal costs, revenue allocation, and rate design issues for a major electric utility. The more recent practice is to adopt settlements on these

---

[23] D.96-04-050 at 19 (emphasis added).

[24] D.96-04-050 at 95 (emphasis added).

[25] D.87-12-033 at 2, citing D.86-08-083 at 62, Conclusions of Law 26-27.

issues. As such, D.96-04-050 contains perhaps the fullest discussion of these issues among all Commission decisions issued since 1990.

Our adoption of settlements is not precedential.[26] Therefore the findings and conclusions of D.96-04-050 remain valid and should be regarded as the starting point for the Commission's evaluation of whether revenue allocation and rate designs are reasonable.[27] To summarize, the history of Commission decisions considering EPMC shows that it is a cost-based and appropriate way to allocate revenue and design retail rates. We therefore reiterate the findings of these previous decisions and find that EPMC-based rate design is:

- Cost-based;
- A reasonable balance between equity and efficiency in revenue allocation and ratesetting; and
- The Commission's preferred starting point for evaluating the reasonableness of revenue allocation and rate design.

This means that in our evaluation of whether PG&E's proposed revenue allocation and rate designs are reasonable, and therefore whether the settlements on these issues are reasonable, we should use EPMC as a starting point. More generally, we will seek to ensure that the proposed revenue allocation and retail rates fairly assign marginal cost responsibility to the classes and customers within classes that impose those marginal costs on PG&E.

Of course, other considerations may lead us to find that deviations from EPMC-based and marginal cost-based revenue allocation rate designs are

---

[26] Commission Rules of Practice and Procedure, Rule 12.5.

[27] We address below one apparent exception to this general rule that appears in D.11-05-047, which addressed EPMC scaling of certain residential rate components.

reasonable, as we do in this proceeding. In the revenue allocation context, "caps and floors" may be used to limit the rate impact of changes to a class's revenue allocation from one GRC Phase II proceeding to the next.[28] Similarly, in the rate design context, fully cost-based rates may be mitigated in order to ensure that bill impacts between GRC Phase II cycles are not extreme. But an EPMC-based and marginal cost-based revenue allocation and rate design is our favored starting point.

4. Are PG&E's Revenue Allocation, Marginal Cost, and Real-Time Pricing Cost Recovery Proposals Reasonable and Should They be Adopted?

In this second phase of PG&E's 2017 general rate case the Commission is to determine the share of PG&E's revenue requirement (i.e., its forecasted costs) that should be paid for by each customer class. This process of assigning responsibility for shares of PG&E's forecasted costs among customer classes is known as "revenue allocation."

A settlement amongst the parties on marginal cost and revenue allocation issues (MC/RA settlement) was served on October 26, 2017. The settling parties were AECA, CAL-SLA, CFBF, CLECA, CMTA, California State University (CSU), DACC, EPUC, EUF, FEA, Marin Clean Energy (MCE), ORA, PG&E, SBUA, and TURN. The Counties of San Joaquin and Santa Clara participated in settlement negotiations but did not sign the settlement agreement, apparently due to the long lead time required to secure county approval for settlements.[29] In

[28] EPUC-1 at 32 and ORA-1, Chapter 10 at 2-7 for a discussion of the application of caps and floors to limit the rate impact of revenue allocation changes.

[29] Motion to Adopt MC/RA Settlement at 1.

the absence of comments from the Counties of San Joaquin and Santa Clara that they oppose the settlement, we consider the MC/RA settlement uncontested.

In the MC/RA settlement, PG&E defines the following customer classes for the purposes of revenue allocation:

- Residential
- Small Light & Power (i.e., small commercial and industrial customers)
- Medium Light & Power (i.e., medium commercial and industrial customers)
- E-19 (i.e., large commercial and industrial customers)
- Streetlights
- Standby customers[30]
- Agriculture
- E-20T (i.e., very large commercial and industrial customers connected to PG&E's transmission network)
- E-20P (i.e., very large commercial and industrial customers connected to PG&E's primary distribution network)
- E-20S (i.e., very large commercial and industrial customers connected to PG&E's secondary distribution network)

PG&E also splits each of these customer classes between those customers that take generation service from PG&E ("bundled customers"), and those that take generation service from a non-PG&E provider such as a community choice aggregator. This brings the total number of PG&E customer classes subject to revenue allocation to 20.

---

30 Those customers that generate their own power but rely on the PG&E system for backup purposes.

Because average rates are calculated by dividing the revenue allocation by the expected sales for that class, the revenue allocation has a direct effect on the average rate for electricity faced by a customer in the class.

For example, if we estimate that residential customers will consume 10 million kilowatt hours (kWh) in a year and residential customers are responsible for $1 million of PG&E's authorized budget, then the average rate for residential customers will be $0.10/kWh ($1,000,000 / 10,000,000kWh). If we instead determine that residential customers are responsible for $1.2 million of PG&E's authorized budget, then the average residential rate in this example rises to $0.12/kWh.

Revenue allocation therefore has a direct and linear impact on the class average retail rates faced by customers in that class.[31] All else being equal, if revenue allocation to a particular class is reduced by 3% then that class will see a 3% reduction in their average rate.[32] The reverse is also true. If revenue allocation to a particular class is increased by 3%, then the average retail rate for that class will also increase 3% if all else is equal.

Because revenue allocation has a direct impact on the rates faced by customers, the Commission is obligated to consider whether the revenue

---

[31] Individual customers in a given class may face average rates that differ greatly from the class average rate, due to differences in individual load profiles. For example, schools and large retailers may be members of the same class (e.g., E-19) but may have greatly differing load profiles and pay differing average rates.

[32] All else is usually not equal. This example assumes that several other drivers of increased rates remain constant, including forecasted sales and the wholesale price of electricity. In reality, a customer's actual rate may rise even if the revenue allocation is reduced.

allocation assigned to each of PG&E's 20 customer classes leads to just and reasonable rates.[33]

As discussed previously, the Commission's recent practice is to adopt settlements between parties that determine the revenue allocation for the customer classes of electric utilities. The most recent Commission decision confronting the issue of revenue allocation for a large electric utility did so. That decision in SDG&E's GRC Phase II found that the settlement of the parties on revenue allocation issues was acceptable for a number of reasons, and highlighted the "give-and-take" between the parties in negotiating a settlement and the lack of a disproportionate rate impact on any customer class arising from the settlement.[34]

Critically, the particular marginal cost proposals of the settling parties in that proceeding were not adopted.[35] In other words, the adopted revenue allocation in that decision did not rely on any actual marginal cost values. The decision instead relied on the variety of stakeholders engaged in the settlement negotiations, their apparent good-faith compromise, and the fact that rate impacts were capped as evidence that the settlement on revenue allocation was reasonable.

This determination in D.17-08-030, and many other decisions accepting revenue allocation settlements, may be interpreted as somewhat at odds with the

---

[33] Public Utilities Code Section 451.

[34] D.17-08-030 at 14.

[35] D.17-08-030 at 13 ("The Settling Parties [citation] were able to reach agreement on the allocation of SDG&E's total revenue requirement among the rate classes, thereby making moot the need to litigate and resolve the differences regarding proposed marginal cost methodologies and forecasts").

idea that marginal cost responsibility of each customer class should determine the revenue allocation for that class, as discussed above in Section 3 in our review of previous Commission decisions on the use of EPMC. Many other factors may determine the reasonableness of a revenue allocation determination, and these factors may in fact be more important than marginal cost responsibility.

The parties to the MC/RA settlement in this proceeding granted as much during their examination by the assigned ALJs on February 14, 2018. They affirmed that while certain marginal costs calculations were included in their settlement negotiations,[36] they simultaneously considered caps on allocation changes that would ameliorate bill impacts for all customer classes.[37]

There were a variety of proposals for revenue allocation from the parties. For example, PG&E originally proposed a 0.16% increase to the revenue allocation for the bundled E-19 class, while ORA proposed a 2.92% increase. And CLECA/CMTA proposed a 4.7% decrease for the same class, while TURN proposed a 0.6% increase.[38] Similar divergence in the proposals for revised revenue allocations were seen across several other classes.

Complicating matters further, some of the settling parties believed that the upcoming changes in TOU peak periods were sufficient reason to limit or eliminate the use marginal cost responsibility to adjust the revenue allocation.[39]

---

[36] Transcript at 494.

[37] Transcript at 477-480.

[38] PG&E-48 at 3.

[39] Transcript at 483, 487 (PG&E affirming that for bundled residential customers, a small revenue allocation change "is based solely on PG&E's recommendation to change the public purpose program allocations and included no change to distribution or generation so, therefore,

Footnote continued on next page

In other words, the parties to the MC/RA settlement in this proceeding were concerned with far more than simply marginal cost responsibilities for each class, and eventually the settling parties chose not to use any single party's proposed marginal costs. Instead, the parties created "black box" (i.e., artificial) marginal cost values that would lead a computer model to produce their desired revenue allocation outcome.[40] This leads to an interesting result where we find that the marginal cost proposals of PG&E, as modified by the settlement, are reasonable in spite of the fact that the settling parties did not actually agree on particular marginal generation capacity cost values for each class.[41] For reasons spelled out below, we find that the marginal cost proposals for the purpose of revenue allocation are reasonable in spite of their artificial nature due to the fact that they prevent any one customer class from facing large changes in revenue allocation and commensurate changes to their average rate. This is an example of an instance where we approve a revenue allocation that may not be strictly

---

did not use any marginal costs in determining that change"); Transcript at 504 (CFBF affirming that "[we] supported PG&E's opening position that there should be essentially no change in the revenue allocation to each customer class. From our perspective, that was based on, as [PG&E] stated, the transition to new TOU periods"); Transcript at 506 (CLECA stating that "[with respect to] not moving toward marginal costs [in this proceeding], I mean, you just deal with the numbers in the next case. I think it's important to reflect the reality of the situation that we're in in the current time. That being the move to [TOU rates]. And we haven't done it for almost 30 years").

[40] Transcript at 492 (PG&E affirming that "[t]he [settling] parties performed a number of scenarios taking into account all of the various parties' opening positions and compromises. There were a series of negotiations over several weeks as we adjusted marginal cost values for purposes of getting the model to work and produce revenue allocation results. At the end of the day, the parties agreed on the percentage changes to the revenue allocation not on the marginal costs themselves").

[41] County of Santa Clara and County of San Joaquin Reply Brief at 4 ("[g]iven the disparate proposals reflected in testimony, where different methodologies result in very different marginal cost outcomes, all that is known is that compromises were made").

based on true marginal cost responsibility or EPMC principles due to countervailing considerations.

Our standard for reviewing uncontested settlements appears above in Section 2. We must review the MC/RA settlement to determine if it is reasonable in light of the whole record, consistent with law, and in the public interest. We reviewed the settlement's terms, and the ALJs assigned to this proceeding examined witnesses testifying on behalf of the settling parties on February 14, 2018. We find that the MC/RA settlement should be approved, with one minor clarification, for reasons including the following:

- Parties representing all customer groups presented testimony on revenue allocation issues.
- Parties worked diligently and focused on multiple simulations outlining all litigated positions, and ultimately agreed to focus on rate impacts rather than marginal cost responsibility.[42]
- The result is a balanced settlement for all ratepayers.
- There are very mild changes in revenue allocation compared to PG&E's existing revenue allocation, which minimizes the impact of the MC/RA settlement on average rates.[43]

We therefore find that PG&E's revenue allocation and marginal cost proposals, as modified by the MC/RA settlement, are reasonable and should be adopted. However, we do not accept the MC/RA settlement's proposal that the separate "tree mortality program" non-bypassable charge (NBC) under development in A.16-11-005 will be calculated as a separate charge and added to

[42] Transcript at 497-498.

[43] Transcript at 499 (ORA affirming that "[i]n this particular case, ORA agrees with PG&E that the conditions are quite unusual, and that there's a lot of changes going on. And, hence, we think it's better to have the changes to all of the customer classes as small as possible").

public purpose program (PPP) rates.[44] Whether or not to include a tree mortality NBC in the PPP is an issue under discussion in the application (A.) 16-11-005 proceeding, and we will not prejudice the outcome of that proceeding in this decision. The matter of how to charge the tree mortality NBC remains open until resolved in A.16-11-005.

We find that PG&E's proposed revenue requirement increase of approximately $510,000 for recovery of certain costs incurred to develop a real time pricing proposal is reasonable and should be adopted, as the recovery of these costs were sought through a rate design proceeding as ordered by D.08-07-045,[45] and none of the parties to the MC/RA settlement objected to the recovery of these costs.

Finally, we find that PG&E's proposal to reallocate SGIP-related revenue among the classes on an annual basis pursuant to Resolution E-4926, rather than a triennial basis, is reasonable and should be adopted.

We direct PG&E to implement the resulting revenue allocation as soon as practicable following the issuance of this decision. The revenue allocation will apply to any future changes in PG&E's rates until the decision in the next PG&E GRC Phase II proceeding is adopted.

---

[44] MC/RA Settlement at 17, fn 15.

[45] Ordering Paragraph 15 of D.08-07-045 states that "PG&E is authorized to [create] a memorandum account and shall seek recovery of any such [real time pricing] expenditures in a related rate design proceeding." Earlier in the decision (at 81-82), the Commission rejected a request by PG&E to recover costs via a balancing account because there would be insufficient record and no opportunity for a reasonableness review.

5. Reasonableness of PG&E's Proposed TOU Periods and Seasons

Updating TOU periods to reflect the current electric system marginal costs faced by the utilities is a high priority for the Commission. D.17-01-006 describes the principles we should adhere to when considering whether to change the current TOU periods and provides a summary of the purpose of TOU periods and rates. While the principles of D.17-01-006 are not binding on this rate design application, we will assess how the settling parties' proposed changes fit with the guidance set forth in that decision.

D.17-01-006 at 4 states "[h]istorically, TOU rate intervals were designed to reflect time variations in the cost to serve loads, with high-priced periods during summer week-day afternoons when the loads were highest. Setting higher TOU rates during peak periods signals that electricity is more valuable at certain times of the day and provides customers an incentive to reduce energy use or to generate on-site energy using renewable or other technologies at those times."

Consistent with the guiding principles set out in D.17-01-006, "base TOU periods should be based on utility-specific marginal costs, rather than on a statewide load assessment. This marginal cost analysis should use marginal generation cost, consisting of marginal energy costs and marginal generation capacity costs. Going forward, the [utilities] should include information on marginal distribution costs that contribute to peak load costs and time of use information filed or adopted in Federal Energy Regulatory Commission transmission rate proceedings. Use of marginal distribution and transmission cost information in setting future Base TOU periods will be addressed in individual [utility] rate proceedings."[46]

D.17-01-006 also found that "[t]he [California Independent System Operator (CAISO)] analysis shows a potential for curtailment of grid-connected solar generation during minimum load events primarily in the early spring"[47] and "[w]here a utility utilizes two seasons for differentiating TOU rate time periods, it is reasonable to consider proposals to create an overlay of an elective or optional third season for super-off-peak usage."[48]

D.17-08-030 implemented the vision of D.17-01-006 in the context of the recent SDG&E GRC Phase II. In D.17-08-030 we analyzed marginal cost data relevant to SDG&E's network, and held that SDG&E's existing peak period of 11 a.m. to 6 p.m. should shift to 4 p.m. to 9 p.m., and that this shift was justified in light of changes to SDG&E's peak load and cost patterns in recent years.[49] We also held that a super-off-peak period during the spring was justified between 10 a.m. and 2 p.m. in March and April.[50]

The data PG&E used in the instant proceeding to propose changes to its summer season and TOU period definitions are based on PG&E's forecasted Adjusted Net Load (ANL)[51] for the year 2020. This 2020 ANL forecast was used

---

[46] D.17-01-006 at 7.

[47] D.17-01-006, Finding of Fact 12.

[48] D.17-08-030, Finding of Fact 22.

[49] D.17-08-030 at 20-26.

[50] D.17-08-030 at 25.

[51] PG&E-9, Chapter 2 at 8 defines ANL as CAISO's net load calculation (which already deducts wind and solar resources from gross load) less of nuclear, hydroelectric and other renewable

Footnote continued on next page

to produce marginal generation cost estimates, by hour, for 2020. PG&E then defined "high cost hours" as those in either the Top 100 or Top 250 of the forecasted marginal generation cost hours for 2020.[52] PG&E also examined the Top 5% of forecasted marginal generation cost hours to refine TOU periods once established using the Top 100 and Top 250 hours.[53] Additionally, PG&E looked to the peak hours of load on their distribution circuits, in addition to peak hours for marginal generation costs, when determining the appropriate summer part-peak period in accordance with the principles outlined in D.17-01-006.[54]

Basing a TOU peak period analysis on ANL was noted by D.17-01-006 as being more closely aligned with marginal cost forecasts than other models,[55] and distribution circuit cost modeling is also embraced by D.17-01-006 as a way to help design TOU periods.[56] As a result, we find that PG&E complied with the principles outlined in D.17-01-006 by using marginal generation costs, as represented by ANL, and distribution contributions to peak demand to determine appropriate TOU seasons and periods.

---

resources such as biomass and geothermal. Essentially, ANL represents that amount of PG&E load served by thermal generation, imports, and energy storage.

52 PG&E-9, Chapter 12 at 8, noting that the use of the Top 100 hours for this purpose is consistent with historic Commission rate design proceedings, and that the Top 250 hours have been used to determine avoided costs in a different Commission proceeding (Rulemaking [R.] 07-01-041).

53 PG&E-9, Chapter 12 at 7-9.

54 PG&E-9, Chapter 12 at 14-15.

55 D.17-01-006 at 27.

56 D.17-01-006 at 27.

5.1. Proposed Summer Season of June-September

We now turn to the question of whether the TOU seasons proposed are reasonable in light of the data provided by PG&E. PG&E currently utilizes a six month summer season from May – October and a six month winter season from November – April for most of its non-residential customers.[57] PG&E and the settling parties propose to shorten PG&E's summer season to a four month period from June – September, and lengthen PG&E's winter season to an eight month period from October – May.

PG&E's testimony asserts that an analysis of their marginal generation costs by month showed that the majority of PG&E's highest cost hours[58] are forecasted to occur in June – September 2020. They also assert that May and October see less than one percent of the highest cost hours over the course of that forecasted year. Accordingly, PG&E proposed setting June – September as the appropriate summer season to reflect the time of year with the highest cost hours.[59] The settlements in this proceeding that concern rates with seasonal differences universally support the revised summer season definition.

In light of the testimony provided by PG&E and the unanimous support for the seasonal definition in the settlements, we find that a summer season of June – September for PG&E's TOU customers is reasonable in light of the whole record, consistent with law, and in the public interest. Further, this shortened summer season comports with our shortening of SDG&E's summer season in

---

[57] D.15-11-013 established a June – September summer for PG&E residential customers taking service on certain TOU rates.

[58] On either a Top 100 hour-basis or a Top 250 hour-basis.

[59] PG&E-9, Chapter 12 at 9-10.

D.17-08-030.[60] We direct PG&E to implement the revised summer season as soon as practicable following the issuance of a final Commission decision in this proceeding.

We note, however, that PG&E's testimony reflects that the month of June has considerably fewer high cost hours compared to the months of July – September, and on a Top 250 hour-basis June has a *smaller* percentage of high cost hours as compared to October, November, or December.[61] While we do not believe it is unreasonable to include June in the summer season at this time, we order PG&E to refresh its data appearing in Chapter 12 of PG&E-9 for its next GRC Phase II application and describe why June should or should not be included in its summer season in that application. PG&E shall also include illustrative rate impacts that would result from 1) a shortening of PG&E's summer season to July – September for all of its customer classes on seasonal rates, and 2) a revision of the summer season to July – October for all of its customer classes on seasonal rates.

5.2. Proposed TOU Period Definitions

The parties to the various settlements at issue in this decision agreed to apply consistent TOU period definitions across all TOU rates offered by PG&E to its non-residential, non-agricultural customers.[62] These period definitions appear below.

- Peak Period: 4 p.m. to 9 p.m., all days of the year

---

[60] D.17-08-030 at 15-17, shortening SDG&E's summer season from May – October to June – October.

[61] PG&E-9, Table 12-2.

[62] With certain exceptions such as the A-1 STORE rate.

- Part Peak Period: 2 p.m. to 4 p.m. and 9 p.m. to 11 p.m., every day during the summer months only
- Super Off-Peak Period: 9 a.m. to 2 p.m., every day in March, April, and May only
- Off-Peak Period: All remaining hours

We note that these periods do not align with PG&E's original proposal, where peak hours were defined as 5 p.m. to 10 p.m. PG&E's testimony rejected a potential 4 p.m. to 9 p.m. peak period by claiming that it was not as good a match for the high cost hours of the day when compared to the 5 p.m. to 10 p.m. peak period. PG&E's data indicated that the 4 p.m. to 5 p.m. hour only includes 2% of the most costly hours of the 2020 forecast, while the 9 p.m. to 10 p.m. hour includes 6% of the Top 250 hours and 12% of the Top 100 hours.[63]

PG&E eventually justified its proposed peak and part-peak periods by calculating the number of high cost hours captured by the period, as well as by examining the number of low cost hours that were included in any given combination of peak and part-peak periods. This analysis led PG&E to recommend a peak period of 5 p.m. to 10 p.m. every day of the year, a summer part-peak period of 3 p.m. to 5 p.m. and 10 p.m. to 12 midnight every day of the summer, and a super off-peak period of 10 a.m. to 3 p.m. every day in March, April, and May.[64]

The settling parties, including PG&E, modified PG&E's original proposal and effectively pushed back the originally proposed TOU periods by one hour. Various parties provided testimony on the issue of appropriate TOU peak

[63] PG&E-9, Chapter 12 at 11.

[64] PG&E-9, Chapter 12 at 10-19.

periods, including SEIA, CALSSA, CLECA, SBUA, ORA, and others. Party testimony demonstrated reasonable grounds for disagreement concerning the proper peak and part-peak hours for PG&E.[65]

We accept that the settling parties considered this testimony and engaged in substantial give-and-take concerning the peak periods to be employed by PG&E. We also reiterate our findings from D.17-01-006 and D.17-08-030 that revisions to the TOU period definitions utilized by California's electric utilities are necessary and in the public interest given the current conditions faced by California's electricity grid. As the proposed PG&E peak summer TOU period of 4 p.m. to 9 p.m. aligns with that approved for SDG&E in D.17-08-030, utilizes data recommended by D.17-01-006, and is generally reflective of the highest marginal cost hours experienced by PG&E, we find that it comports with our current position on an appropriate peak period definition and is approved.

5.2.1. TOU Periods for Agricultural Customers

In the case of agricultural customers, the parties to the Agricultural Rate Design settlement seek definitions of peak and off-peak periods that are distinct from the TOU periods described above. That settlement seeks a 5 p.m. to 8 p.m. peak period during all days of the year, with all other hours being off-peak. No super off-peak or part-peak periods are proposed.[66]

This is a significant change from the TOU period definition proposed for PG&E's other non-residential TOU rates. However, PG&E's testimony in

---

[65] CLECA-1 at 73-84, discussing the advantages and disadvantages of PG&E's original proposal and ORA's proposal for a 3 p.m. to 9 p.m. summer peak period; and SEIA-1 at 7-9, proposing a summer peak period of 3 p.m. to 8 p.m. based on an analysis of PG&E's total system marginal costs.

[66] Motion to Adopt Agricultural Rate Design Settlement at 6.

support of the narrow agricultural peak period notes that the 5 p.m. to 8 p.m. period falls within the proposed 4 p.m. to 9 p.m. peak period, and that agricultural customers have specific operational constraints that favor an early daily end to the peak period.[67] The 5 p.m. to 8 p.m. peak period is also supported by parties representing agricultural customers, namely CFBF.[68] Parties to the agricultural settlement testified that an earlier end to the peak period is necessary for agricultural customers so that they may safely inspect their equipment before the start of the off-peak period. The daylight still available at 8 p.m. during the summer would apparently allow for safe inspections.[69] Therefore, particular operational needs of agricultural customers justify an earlier end to the peak period than for non-agricultural customers.

In light of these settlement negotiations, the good faith efforts of the parties to resolve this issue, and our previous findings with respect to TOU period modifications, we find that the new TOU periods as defined by the various settlements in this proceeding are reasonable in light of the whole record, consistent with law, and in the public interest. We direct PG&E to implement the revised TOU periods appearing in the various settlements in this proceeding as soon as practicable following the issuance of a final Commission decision in this proceeding.

---

[67] PG&E-53 at 5.

[68] CFBF-3 at 13 ("Farm Bureau supports PG&E's Rebuttal Testimony proposals for the new TOU period definitions…").

[69] Transcript at 1231-1233.

6. Are PG&E's Rate Design Proposals Reasonable and Should They be Adopted?

Once revenue requirements are allocated to customer classes and time of use and seasonal definitions are adopted, we must design rates to collect the allocated revenues. Each of PG&E's customer classes has unique issues that we grapple with below. Our goal in adopting particular rate designs is to ensure that the adopted rates result in revenue collection equal to the costs allocated to that class while simultaneously meeting our other rate design objectives.

Previously in this decision, we reviewed the history of the EPMC methodology and reiterated our previous findings that it is an appropriate starting point for rate design. We also noted that there are other principles that influence our determination of whether a given rate design is reasonable, and therefore whether a given settlement on rate design issues is reasonable. Over the years, the Commission has articulated its rate design principles as follows:[70]

1. Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost;
2. Rates should be based on marginal cost;
3. Rates should be based on cost-causation principles;
4. Rates should encourage conservation and energy efficiency;
5. Rates should encourage reduction of both coincident and non-coincident peak demand;
6. Rates should be stable and understandable and provide stability, simplicity and customer choice;

[70] D.17-08-030 at 30-31; D.17-01-006 at 37; D.15-07-001 at 27-28 (noting that the principles were developed after receiving extensive input from parties).

7. Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals;
8. Incentives should be explicit and transparent;
9. Rates should encourage economically efficient decision-making; and
10. Transitions to the new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

As we review the numerous rate design issues and proposals in this proceeding, we will consistently return to these guiding principles to assist in our evaluation of whether PG&E's proposed rate designs are reasonable.

6.1. The Reasonableness of TOU Rates in General

Most of PG&E's non-residential customers[71] have transitioned to mandatory TOU rates. Various Commission decisions in the last several years have memorialized our commitment to TOU rates in general as a cost-based form of rate design that can enhance bill savings for those customers that shift usage to off-peak periods and reduce utility expenditures on marginal investments. As stated in D.17-08-030: "As evidenced by a review of recent CPUC decisions, the CPUC is moving to greater use of TOU and other time-varying rates. TOU is now mandatory for all [commercial and industrial] customers, we have established a transition plan for residential customers to move to default TOU rates, and TOU rates are now mandatory for NEM 2.0

[71] TOU rate design for residential customers is scoped into R.12-06-013 and consolidated rate design window proceedings Applications (A.) 17-12-011, A.17-12-012, and A.17-12-013, and is outside the scope of this proceeding

customers."[72] It is, therefore, Commission policy that TOU rates in general are reasonable and should be adopted for PG&E's customers.[73]

6.2. PG&E's Proposed Non-Residential Rate Designs Generally Diverge from Our Previous Decisions and State Policy

We address the reasonableness of each category of PG&E's proposed rate designs in light of the EPMC methodology and our rate design principles in more detail below. At this time, we discuss PG&E's broad rate design approach for its commercial, industrial, and agricultural customers and why it does not comply with our previous decisions or state policy.

6.2.1. PG&E's Rate Design Policies

In this proceeding, PG&E has made clear that its "rate design policies for distribution," as well as its "Cost of Service and Rate Design Guidelines" call for basing time-related rate components on <u>unscaled</u> marginal cost, while other, non-time-based rate components, are based on EPMC-scaled marginal cost. As stated by PG&E with respect to its large commercial and industrial customers:

> PG&E's cost of service for distribution is developed based on Marginal Distribution Capacity Costs (MDCC) and Marginal Customer Access Costs (MCAC). These marginal cost values are used in revenue allocation and as the basis to establish distribution rates.[74]
>
> MCAC serve as the basis of customer charges. For rate design, PG&E **scales** the MCAC up by the Equal Percent of Marginal Cost

[72] D.17-08-030 at 45.

[73] D.17-01-006 at 4 ("TOU rates better reflect cost causation and motivate customers to shift their usage to periods that promote more efficient use of the electrical system").

[74] PG&E-39 at 2.

> (EPMC) multiplier associated with PG&E's total distribution revenue. Where the proposed customer charge does not collect the fully-scaled marginal cost, the additional customer-related revenue responsibility will necessarily be assigned to the demand and/or energy charges that do not vary by time of day.[75]
>
> All distribution revenue on Schedules E-19V, E-19 and E-20 are collected entirely in distribution demand charges or customer charges. For these schedules, **unscaled** [Primary Distribution Capacity Costs] are assigned to TOU period and become the basis for the peak and partial peak demand charges. To establish the basis for the proposed non-coincident demand charge on these schedules, PG&E subtracts customer charge revenue and the revenue associated with peak and partial peak demand charges from the distribution revenue assigned to the class. All remaining distribution revenue, including that portion of the revenue made up by the EPMC multiplier, is assigned to a non-coincident demand charge.[76]

While the above-quoted PG&E rate design policies and guidelines for EPMC scaling were stated in reference to distribution rate design, PG&E has also chosen not to scale its time-dependent generation marginal costs.

> Marginal generation capacity costs vary by time of day and are assigned to the summer peak and part-peak periods. Marginal generation energy cost revenue is also developed and assigned to TOU periods. In this proceeding, PG&E has assigned marginal generation cost revenue to each of the new non-residential TOU periods set forth in Exhibit [PG&E-9], Chapter 12. **Like distribution, PG&E proposes to base its proposed generation rates on [unscaled] marginal generation cost differences by season and TOU period.**[77]

---

[75] PG&E-39 at 3 (emphasis added).

[76] PG&E-39 at 4 (emphasis added).

[77] PG&E-8, Chapter 1 at 9-10 (emphasis added).

Returning to distribution, PG&E supports its preference not to scale time-dependent rate components as follows, citing to a Commission decision for support:

Marginal cost revenue is used by PG&E in this instance (in preference [to] marginal cost scaled by the EPMC factor) to ensure that pricing differentials are based only on marginal costs and are not exaggerated. The Commission previously found that using scaled marginal cost to establish TOU differentials in rates would provide a benefit to customers that shift use that is more than the avoided cost, and would result in cost shifting. *See* D.11-05-047, at 68-71, and Finding of Fact (FOF) 40.[78]

6.2.2. Parties' Opposition to PG&E's Approach

CLECA took exception to PG&E's proposal to use unscaled marginal costs in rate design. Unlike PG&E, CLECA testified that EPMC scaling should apply to all rate components for large non-residential customers, including time-related rate components. CLECA states its rate design principle for E-20 customers as follows:

> These rates should be based on cost-of-service principles using updated marginal costs. The residual amount between the marginal cost revenues and the full revenue requirement for distribution and generation should be assigned on an equal percent basis to the individual rate components. (We will refer to this amount as the EPMC factor for each rate component.) However, if the full cost-of-service rates (marginal cost plus EPMC factor) would result in a very large change in one or more rate components, the change

---

[78] PG&E-39 at 4, fn 5.

> should be mitigated and phased in over more than one year or rate case cycle, depending on the potential bill impacts.[79]

Accordingly, CLECA rejects PG&E's proposed use of unscaled marginal cost in generation rate design:

> PG&E's proposed generation rate design deviates significantly from marginal cost pricing principles because the demand charges have been artificially lowered from the full cost-of-service level and the energy charges have been deliberately flattened out by assigning these capacity-related revenues equally to all TOU periods. This makes no sense because capacity costs are not incurred equally in each TOU period.[80]
>
> A rate that incorporates an EPMC scaling of each generation rate component results in TOU ratios that are equal to the TOU ratios in the [marginal energy costs (MECs)]. PG&E's rate proposal dramatically reduces all of the TOU ratios as compared with the TOU ratios inherent in PG&E's MECs. PG&E's proposed rates are greatly reduced even when compared to the TOU ratios inherent in current rates. PG&E's proposed rates run counter to Commission policies that support TOU pricing based on marginal cost analysis and should be rejected.[81]

Finally, citing D.16-11-021 and D.17-01-006, CLECA states:

> PG&E's reduced on-peak demand charges will also reduce incentive to shift load to avoid coincident demand charges. For all these reasons, PG&E's large power rate design is not consistent with Commission policy direction.[82]

---

[79] CLECA-1 at 101.

[80] CLECA-1 at 104.

[81] CLECA-1 at 106.

[82] CLECA-1 at 107.

Beyond the context of the large commercial sector discussed by CLECA, other parties criticized PG&E's general approach of flattening or otherwise moving away from cost-based rates for its non-residential TOU customers. For example, AECA testified that agricultural customers that have made investments in energy efficient technology and pursued other behaviors that can take advantage of load-shifting opportunities would be harmed by the flattened rates proposed by PG&E.[83]

We recite this testimony to make clear that PG&E's originally proposed rate designs and certain settlement rate designs did not adequately consider EPMC or, as shall be detailed later, marginal cost responsibility.

6.2.3. Summary of PG&E's Proposed Flattened Rate Differentials

To illustrate the real-world impact of PG&E's rate design proposals as expressed in the various settlements in this proceeding, the table below summarizes the existing premium of summer peak energy charges versus off-peak energy charges for PG&E's non-residential TOU customers, and compares them with the proposed summer peak premiums for those customers.[84] It is evident that PG&E and the settling parties either held or dramatically reduced the differential between peak and off-peak summer energy charge prices for these customers, with the exception of A-1 and A-10-T customers.

[83] AECA-1 at 26; Transcript at 1201-1203 (noting as well that agricultural parties expect to revisit PG&E's rate designs as soon as possible to improve their cost-basis).

[84] All comparisons are based on current and illustrative rates for each rate schedule as they appear in the rate design settlements in this proceeding.

Rate Schedule	Existing Summer Peak Price Premium	Settlement's Proposed Summer Peak Price Premium	Settlement's Proposed Reduction in Peak Premium
A-1 TOU	16%	31%	N/A[85]
A-6	198%	55%	72%
A-10-T TOU	74%	84%	N/A
A-10-P TOU	60%	60%	0%
A-10-S TOU	62%	61%	2%
E-19-S	80%	43%	46%
E-19-S (Option R)	302%	220%	27%
E-19-P	80%	38%	53%
E-19-P (Option R)	310%	220%	29%
E-19-T	38%	26%	32%
E-19-T (Option R)	259%	136%	48%
E-20-S	77%	42%	46%
E-20-S (Option R)	287%	219%	24%
E-20-P	84%	44%	48%
E-20-P (Option R)	317%	216%	32%
E-20-T	39%	37%	5%
E-20-T (Option R)	275%	204%	26%

This trend is also evident in the proposed price premium of time-related summer demand charges to non-time-related (i.e., non-coincident or "maximum") summer demand charges for PG&E's E-19 and E-20 customers (no other

[85] Because A-1 TOU and A-10-T TOU rates see increases in the price premium under the settlements in this proceeding, they are assigned "N/A" values in this table.

customers face peak period demand charges).[86] With the exception of the E-20-T schedule, PG&E and the settling parties propose to substantially reduce the price premium for peak period demand charges, and in some cases propose peak period demand charge prices that are less than the non-coincident demand charge price.

Rate Schedule[87]	Existing Peak Demand Charge Price Premium	Settlement's Proposed Peak Demand Charge Price Premium	Settlement's Proposed Reduction in Peak Premium
E-19-S	106%	94%	-12%
E-19-P	115%	101%	-14%
E-19-T	136%	81%	-55%
E-20-S	103%	89%	-14%
E-20-P	128%	105%	-23%
E-20-T	191%	177%	-14%

Another way of examining PG&E's proposals is to examine the percentage of distribution revenue that PG&E currently collects from those customers through peak demand charges compared to the percentage that PG&E proposes to collect through peak demand charges.[88]

---

86 We define the price premium as the extra amount per kW that a customer would pay if their non-coincident demand occurred during a peak period, or ((maximum demand charge + peak demand charge) / maximum demand charge) -1.

87 Option R rates are not included as they already face extremely limited peak period demand charges. It should be noted that proposed prices for Option R non-coincident demand charges increased while the peak demand charge prices remained relatively flat.

88 As presented in PG&E-39, Attachment 2.

Rate Schedule[89]	Current Percentage of Distribution Revenue Collected Through Peak and Part-Peak Demand Charges	Settlement's Proposed Percentage of Distribution Revenue Collected Through Peak and Part-Peak Demand Charges
E-19-S	25.8%	15%
E-19-P	29.2%	17.3%
E-20-S	27.2%	14.7%
E-20-P	32.2%	15.7%

In hearings, PG&E suggested that the reduced revenue collection through peak and part-peak demand charges for E-19 and E-20 customers was the result of shortening the length of the summer by one-third (i.e., shortening the six-month summer to four months).[90] However, given that the reductions in revenue collected through peak and part-peak demand charges far exceed one-third, this explanation is not sufficient. In fact, the average reduction in distribution revenue collected by peak and part-peak demand charges for these customers is 45%.

Further, the logic is unsound for even a one-third reduction in peak-related demand charges due to the shortened summer season. PG&E's rationale for a shorter summer is largely predicated on the fact that marginal capacity costs are concentrated in the core summer months of June through September. Therefore, one would expect little reduction in marginal capacity cost by dropping May and October from the summer period. This leads to the conclusion that roughly the same amount of capacity costs must be recovered

[89] A-10, E-19-T, and E-20-T rates are not included as they do not currently face peak or part-peak demand charges for distribution.

[90] Transcript at 1082-1085.

over four months instead of six months, leading to an increase in peak-related summer demand charges rather than a reduction.

Alternatively, even if the reduction in revenue collected matched the reduction in the summer period itself, that would not explain why the marginal costs that are incurred in the existing May – October summer are not wholly collected through a combination of new summer *and winter* peak demand charges. That is to say, the revenues collected through the proposed peak and part-peak demand charges should either reflect the current revenue collected to account for marginal costs, and if not a new winter peak demand charge should have been created to account for the 2-month reduction in the summer period.

6.2.4. Failure of PG&E's Rate Design Proposals to Comply with California's Energy Policy or Previous Commission Decisions

Given the above analysis, we find that PG&E's proposed rate designs, as expressed in the various settlements in this proceeding, do not comply with California's energy policy or our previous decisions. With respect to California's broader energy policy, the Commission recently stated:

> Noncoincident demand charges incentivize customers to flatten their load, but given high penetration of solar resources, solar-following loads are becoming more desirable to avoid curtailing renewable resources and may be less costly to serve than customers with flat loads. **Noncoincident demand charges can discourage beneficial energy use, such as electric vehicle fleet charging (overnight or during hours with high solar generation), or Reverse Demand Response to encourage customers to use**

> **renewable energy that might otherwise be curtailed due to over-generation conditions.**[91]

We affirm these findings in this decision. PG&E's proposed substantial increases to its non-coincident demand charges at the expense of its coincident demand charges, as illustrated above, therefore do not comply with state policies seeking to incent socially beneficially electricity usage.

Nor do PG&E's proposed rate designs in this proceeding comply with the recommendation of D.17-01-006 for utilities to provide a "menu" of different TOU rate options within classes,[92] with enhanced marginal cost signals.[93] The objective of this menu approach was to give those customers that can adopt load-shifting behavioral changes or technologies firmer price signals with which to assist PG&E in avoiding marginal costs. The storage rates adopted by this decision do not, in and of themselves, satisfy this goal as non-storage customers are not allowed to take service on those rates.

The flattening of price differentials proposed by PG&E in the various settlements for nearly all of its non-residential TOU customers in this proceeding will have several detrimental effects, including: sending flawed price signals to PG&E's customers, incenting inefficient use of electricity that imposes costs on

---

[91] D.17-08-030 at 46 (emphasis added). *See also* EPUC-1 at 29 ("the Commission recognizes that driving customer load profiles in response to price signals is an integral element in California energy policy").

[92] For example, PG&E proposes to flatten its A-6 rate to resemble A-1 TOU, thereby depriving small commercial customers of an option to utilize a strong TOU rate.

[93] D.17-01-006 at 8 ("a menu of TOU rate options should be developed in utility-specific rate design proceedings and should provide rate choices addressing different customer profiles and needs"); D.17-01-006 at 39 ("[m]ost parties agree that there is good reason to offer different TOU rates within a customer class")

society through emissions of greenhouse gases,[94] and overcharging customers for off-peak electricity.

This is especially true for customers who will not face any time-differentiation of distribution rates on default TOU schedules, such as agricultural customers. Those customers that increase their off-peak usage will not be appropriately compensated through the lower rates they would otherwise deserve for helping PG&E to avoid marginal distribution capacity investments.

We therefore find that PG&E's general rate design approach for its non-residential TOU customers, as expressed in the various settlements to this proceeding, whereby it increases non-coincident demand charges at the expense of peak-related demand charges, and flattens price differentials between peak and off-peak volumetric prices, runs counter to California's broad energy policy goals as well as the direction taken by the Commission in D.17-08-030, D.17-01-006, and other decisions.

While we approve most of the settlements on PG&E's rate designs in this proceeding, we wish to state clearly that we approve them in spite of the considerable backsliding away from cost-based rates that the proposals represent.

We also note that the PG&E rate designs generally proposed in this proceeding do not maximize the ability of retail rates to assist with the Commission's Distributed Energy Resources (DER) Action Plan. On November 10, 2016 the Commission endorsed the Distributed Energy Resources

---

[94] CALSSA-2 at 7 shows a heatmap of the hours of the day when PG&E experiences the highest GHG emissions on the margin. These hours generally overlap with the 4 p.m. to 9 p.m. peak period. PG&E's failure to send accurate price signals to customers during those hours will lead to inefficient emissions of GHGs.

Action Plan (DER Action Plan). Distributed energy resources are defined as distribution-connected distributed generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies. To support the continued development of the DER marketplace, the Commission set forth a long term vision and coordinating committee for ongoing coordination of DER activities, including three groups of related proceedings or initiatives:

1. Rates and Tariffs;
2. Distribution Grid Infrastructure, Planning, Interconnection and Procurement; and
3. Wholesale DER Market Integration and Interconnection.

Furthermore, five key vision elements are identified for the Rates and Tariffs proceedings:

A. A continuum of rate options, from the simple to complex, is available for customers, and customers are educated to make informed choices;

B. Rates reflect time-varying marginal cost;

C. Processes for adopting innovative rates and tariffs are flexible and timely;

D. Rates and demand charges better reflect cost causation and capacity benefits of DERs; and

E. Rates remain affordable for non-DER customers.

Under the DER Action Plan, the Commission actively considers ongoing refinements to many DER policies in Commission proceedings. Specifically, the DER Action Plan identifies "consideration of fixed charges, TOU periods and rates, nonresidential rate design, including enhancements to dynamic rates" as a "continuing" element in Rate Design Window and GRC Phase II proceedings, as well as "appropriate rate designs to absorb renewables oversupply." This proceeding's scope and record have in part facilitated an analysis of these expansive and relevant areas of inquiry in alignment with the vision elements discussed above in order to shape California's distributed energy resources future.

For the reasons stated previously, PG&E's rate design proposals in this proceeding generally did not maximize the rate options available to customers or the time-varying marginal cost signals provided to customers. As detailed below, we require PG&E to propose different rate designs in their next GRC Phase II proceeding .

6.2.5. Further Work Required Before PG&E's Next GRC Phase II Proceeding

We appreciate that the transition to new TOU periods will require adjustment on the part of PG&E's non-residential TOU customers, and that is the primary reason that we find most elements of the settlements reasonable. We are also cognizant that PG&E's next Phase II GRC application is scheduled to be filed within the next 12 months. However, as we stated in D.17-01-006, "[a]lthough reflection of cost-causation may be muted when new TOU rates are initially being introduced, over time each rate design should be able to reflect the cost to serve enrolled customers with increasing accuracy."[95]

PG&E is therefore ordered to propose more cost-based rates, based on full EPMC scaling of all marginal cost components, for its non-residential TOU customers in its next GRC Phase II proceeding. PG&E shall also propose an alternative set of rates that, while not based on full EPMC scaling, are more cost-based than those approved by this decision. PG&E must also propose a menu of TOU options for all of its non-residential TOU customers, not simply its

[95] D.17-01-006 at 40.

storage customers, such that those customers that believe they can respond to fully scaled marginal cost-based rates are able to do so.

While retail transmission rates are and remain under the jurisdiction of the Federal Energy Regulatory Commission (FERC), SEIA notes that the Commission can play a role in shaping transmission rates. SEIA states that "[t]he CPUC represents the state of California before the FERC, and participates actively in PG&E's transmission rate cases. SEIA believes that California rate design proceedings such as this one are logical public forums in which knowledgeable and interested parties should be encouraged to provide input to the CPUC on FERC transmission rate design, and in particular on the impacts which FERC rate design may have on the design of CPUC-jurisdictional rates, and vice versa."[96]

SEIA summarized its testimony regarding transmission rate design as follows:

> Testimony in PG&E's prior GRC Phase 2 proceedings have included discussions of the interaction between FERC-jurisdictional trans-mission rates and CPUC-jurisdictional generation and distribution rates. Settlements in Phase 2 cases for San Diego Gas & Electric have included commitments from the utility to pursue before the FERC certain changes in its transmission rate design, including moving to the greater use of time-dependent rates. In Decision 14-12-080, the Commission encouraged PG&E to do so, as well. SEIA has included observations about PG&E's transmission rates to provide a record foundation for such discussions in this case. SEIA observes that transmission rates which use peak and partial-peak energy charges or time-related summer demand charges would more accurately reflect cost causation than the non-coincident maximum demand charges now used to recover

[96] SEIA-1 at 47.

> 100% of transmission costs in most of PG&E's [commercial and industrial] rate schedules.[97]

As SEIA notes, we recently ordered SDG&E to file a transmission study "to examine the appropriate allocation of transmission costs between non-coincident demand charges and system peak demand charges to be filed at the Federal Energy Regulatory Commission prior to the next San Diego Gas & Electric Company Phase 2 General Rate Case."[98]

More recently, we adopted a multi-party stipulation in SCE's Transportation Electrification proceeding (A.17-01-020, et al.) directing SCE to file a request at FERC to modify certain retail transmission rates (now 100% non-coincident demand charges) to include a 30% volumetric TOU component. The adopted stipulation (subject to FERC approval) allocates 30% of transmission costs to volumetric rates and 70% to demand charges, and SCE will update this allocation once it completes a transmission cost study during SCE's current GRC Phase II GRC.[99]

In light of SEIA's testimony, and consistent with our direction to SDG&E and SCE in the decisions cited above, we require PG&E to file a transmission cost causation study with its next GRC Phase II application. This study must examine the appropriate allocation of transmission costs between non-coincident demand charges and system peak demand charges.

---

[97] SEIA-1 at v.

[98] D.17-08-030 at 92, Ordering Paragraph 34.

[99] D.18-05-040 at 114.

6.2.6. PG&E's Argument that EPMC Scaling Results in Cost Shifting is Explicitly Rejected

PG&E argues that application of EPMC scaling to time-dependent marginal costs would result in cost shifting.[100] We reject that argument. Given that fully-scaled EPMC rates have been, and remain, the Commission's standard for cost-based, fair, and equitable non-residential rates, we find that applying this standard does not result in cost-shifting.

On the contrary, failure to scale time-dependent marginal costs in peak energy charges and peak demand charges shifts costs to other rate components, in particular off-peak energy charges and non-coincident demand charges. Customers appropriately shifting usage to off-peak hours would therefore pay more for PG&E's service than they should given the costs to serve them. This is the true cost shift that we seek to avoid through rates with appropriately scaled ratios between peak and off-peak energy prices.

6.2.7. Certain Findings of D.11-05-047 Do Not Apply to Non-Residential TOU Rate Design

PG&E cites D.11-05-047 and its finding that PG&E's E-6 residential TOU rate should not reflect EPMC scaling in support of its argument that EPMC-based rate design leads to cost shifts.[101]

This decision is inappropriately cited in support of PG&E's argument. It is necessary to fully explain the inapplicability of the decision on this issue so that there is no confusion in future discussions of non-residential TOU rate design.

---

[100] PG&E-39 at 4, fn 5.

[101] PG&E-39 at 4, fn 5, citing D.11-05-047 at 68-71 and Finding of Fact 40.

The finding of D.11-05-047 as cited by PG&E, applied only narrowly to PG&E's residential TOU rates, which were, in that era, complex combinations of TOU and steeply-tiered inclining block rates, with four or five rate tiers. The cited discussion states, correctly, that EPMC scaling would result in upper-tier summer peak rates which would be unreasonably high for residential customers.

However, the Commission has not applied inclining block rates to non-residential customers, and the circumstances of D.11-05-047 simply do not apply here, in a non-residential context.[102] In summary, nothing in D.11-05-047 leads us to alter the broad conclusions about the use of EPMC for both revenue allocation and cost-based rate design that are embodied in the corpus of decisions cited previously in this decision.

6.3. Small Commercial Rates

On January 29, 2018, PG&E served a motion for adoption of a supplemental settlement on small light and power (SLP) rate design issues. The settling parties are SEIA, CALSSA, EUF, CAL-SLA, SBUA, ORA, and PG&E. These parties all filed testimony in this proceeding on SLP rate design issues.

PG&E's proposed SLP rate designs concern customers on the following rate schedules: A-1 (and its variants), A-6, A-15,[103] and TC-1.[104] Notably, the settlement states that only A-1 TOU, A-1 STORE, and A-6 will be transitioned to

[102] Residential rate design being largely outside the scope of this proceeding, we make no finding here as to the applicability of EPMC scaling to residential rates.

[103] Generally, a rate specific to direct current (DC) lighting, heating, and/or power services for certain customers taking service on this schedule since 1971 in some areas of San Francisco and Oakland where DC service is available.

[104] Applicable to metered service for traffic control-related equipment operating on a 24-hour basis, owned by governmental agencies and located on streets, highways and other publicly-dedicated outdoor ways and places.

the new TOU periods.[105] The settlement is not clear if seasonal definitions for A-15 customers are affected. To resolve ambiguity, we presume that A-15 customers will face the new seasonal definitions faced by other commercial customers at the same time as other customer classes.

6.3.1. Small Commercial Customer Charges

The SLP settlement proposes moderate increases to customer charges, or maintenance of current customer charge levels. For polyphase A-1 and A-6 customers, the SLP settlement proposes customer charge increases of 25%, while for single-phase customers there is no increase. PG&E's original proposal was to increase the polyphase charges by 100% and the single-phase charges by 50%.[106]

ORA and SBUA each challenged this proposal in their testimony and opposed the proposal on the grounds that customers could not avoid these increased charges through behavioral change.[107] ORA also argued that because the A-1 and A-6 rates capture all customers less than 75 kilowatts (kW) in load, the actual marginal cost differences between 5kW and 75kW customers would not be accounted for in a single customer charge that seeks to account for all customers. In other words, the smaller customers within the A-1 and A-6 rates would be treated unfairly.[108]

It appears that PG&E, ORA, SBUA, and other parties to the SLP settlement bargained during negotiations to reduce PG&E's originally proposed increases in

---

[105] SLP Settlement at 7.

[106] PG&E-8, Chapter 5 at 3.

[107] ORA-1, Chapter 11 at 8; SBUA-1 at 35. SEIA also indicated support for ORA's opposition (SEIA-1 at iv).

[108] ORA-1, Chapter 11 at 8. We note SBUA's lack of support for this contention (SBUA-1 at 40).

customer charges for the SLP classes. We accept that the back-and-forth between the parties on this issue resulted in a reasonable outcome that does not produce unjust or unreasonable rates. Increases to customer charges such as those proposed by the SLP settlement were also accepted under previous Commission decisions, including D.17-08-030 where customer charges for some classes were authorized to increase by 20% a year. We therefore find that the SLP settlement's proposed changes to the customer charges are reasonable in light of the whole record, consistent with law, and in the public interest. We direct PG&E to implement the revised SLP customer charges as soon as practicable following the issuance of a final Commission decision in this proceeding.

However, like all settlement approvals, the finding that the SLP settlement in this proceeding is reasonable is not precedential and may not be cited in the future to support an argument that the Commission generally considers 25% increases in customer charges to be just and reasonable.[109]

6.3.2. A-1 TOU Rate

The SLP settlement proposes energy charges for A-1 TOU customers that are largely consistent with the structure of current rates and actually lower summer part-peak prices. No party chose to litigate the A-1 TOU energy charges and structure. ORA and SBUA were broadly supportive of PG&E's originally proposed A-1 TOU energy charges in their testimony.[110]

---

109 Or as stated in the SLP Settlement itself at 3, "[t]his SLP Settlement Agreement does not constitute and should not be used as precedent regarding any principle or issue in this proceeding or in any future proceeding."

110 ORA-1, Chapter 11 at 12; SBUA-1 at 38.

We therefore find that the SLP settlement on A-1 TOU energy charges and structure is reasonable in light of the whole record, consistent with law, and in the public interest. We direct PG&E to implement the revised A-1 TOU rate as soon as practicable following the issuance of a final Commission decision in this proceeding.

6.3.3. A-1 STORE Rate

The A-1 STORE rate is available to A-1 TOU customers that choose to install an energy storage system and opt into the rate. While not specified in the SLP motion, witnesses testified that qualifying energy storage systems would be any system that would otherwise be eligible for the energy storage incentives in the Self-Generation Incentive Program (SGIP).[111] The illustrative A-1 STORE rate appears to provides significant rate differentials between peak and off-peak pricing throughout the year that may help incent energy storage operation that leads to reductions in GHG emissions.[112] There is a public interest in creating such an incentive for energy storage customers, or as PG&E's witness stated "it's for what the planet needs. I think it's a good thing."[113]

The A-1 STORE rate is distinct from many of PG&E's other non-residential rates in that it applies a part-peak TOU period to the winter months as well as the summer months. While not clearly spelled out in the SLP settlement, a witness testifying on behalf of the SLP settlement mentioned that there is a need

---

111 Transcript at 885.

112 CALSSA-2 at 6, noting that properly aligned peak hours may signal energy storage systems to reduce demand during hours of higher GHG emissions; and SEIA-3 at 1-29, noting that demand charges focused on certain hours of the day (such as that proposed in A-1 STORE from 2 p.m. to 11 p.m.) may help improve the environmental performance of energy storage systems.

113 Transcript at 881.

to ensure that energy storage customers faced sufficient peak to off-peak differentials in the winter as well as the summer to incent energy storage deployment.[114] We infer that this is the reason for the distinct treatment of the part-peak period in A-1 STORE.

The record reflects that the A-1 STORE rate was developed primarily to incent the deployment of energy storage technologies, rather than provide incentives for customers to deploy other resources or behaviors to reduce the peak loads on PG&E's system.[115] While we do not find that the purpose of the A-1 STORE rate to incent energy storage deployment is sufficient reason to reject the settlement, given the other benefits it provides, we do note the existence of a direct subsidy program for customer installation of energy storage systems – SGIP. The SLP settlement does not specify why an additional incentive created by the A-1 STORE rate is necessary to incent energy storage installations given the existence of SGIP.

Because the A-1 STORE rate differs substantially from PG&E's original proposal for an A-1 rate specifically designed for energy storage customers, we presume that there was substantial give-and-take between the settling parties on the issue of how to design the A-1 STORE rate. The SLP settlement appears to represent a reasonable compromise on this issue, and we find that the proposed A-1 STORE rate is reasonable in light of the whole record, consistent with law, and in the public interest. We direct PG&E to implement the A-1 STORE rate as

[114] Transcript at 883.

[115] Transcript at 885-886 (referring to the A-1 STORE rate as "a storage promotional rate").

soon as practicable following the issuance of a final Commission decision in this proceeding.

However, PG&E must clarify two elements of the A-1 STORE rate in the tariff sheet for the rate. These clarifications only appear to have become necessary in light of testimony offered by the SLP settlement panel.

As for the Option S rate approved subsequently in this decision, it is important not to tie the eligibility for the A-1 STORE rate to SGIP eligibility as SGIP is due to retire on January 1, 2020. Eligibility for the A-1 STORE rate must outlive SGIP's planned retirement. Therefore, PG&E shall specify eligibility criteria for A-1 STORE rate participation that do not simply cross-reference to the SGIP Handbook or other SGIP rules. The eligibility criteria must be set out in the tariff sheet and stand on their own.

PG&E must also clarify that the non-coincident demand charge as proposed for the rate only applies between the hours of 2 p.m. and 11 p.m.[116]

6.3.4. A-6 Rate

PG&E's originally proposed A-6 rate represented a substantial change from the existing A-6 rate. The differential between peak and off-peak prices in the summer was proposed to be narrowed from 37 cents/kWh to 11 cents/kWh.[117]

There was little if any discussion of this particular rate design issue in the prepared testimony of the settling parties. The County of San Joaquin broadly

---

[116] Transcript at 887-888, PG&E testifying that "it is a 2:00 to 11:00pm demand charge."

[117] PG&E-8 at 55.

criticized the A-6 rate proposal made by PG&E,[118] but they have litigated their concerns with the A-6 rate as applied to Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) customers and are not a party to the SLP settlement.

The A-6 rate design as proposed in the SLP settlement is similar to PG&E's original proposal. The peak to off-peak price differential in the summer is lowered to roughly 12 cents/kWh, and the summer part-peak period is eliminated for customers on this schedule.[119] Because there is very little record analyzing the proposed A-6 rate structure, the rate structure was included as part of an arm's-length settlement reached with parties representing the interests of this class of ratepayer, and because we presume that the flattened A-6 price differentials are intended to promote customer acceptance of new TOU periods, we find that the SLP settlement's proposed A-6 rate structure is reasonable in light of the whole record, consistent with law, and in the public interest. We direct PG&E to implement the revised A-6 rate as soon as practicable following the issuance of a final Commission decision in this proceeding.

We note, however, that the changes made to the A-6 rate exemplify how the rate design principles used by PG&E in this proceeding diverge from our previous decisions and state policy. PG&E is reminded that it must propose a more cost-based rate for A-6 customers in its next GRC Phase II application, and include an optional rate for A-6 customers that uses an enhanced marginal cost signal.

---

118 County and Santa Clara and County of San Joaquin (CSC/CSJ)-1 at 10.

119 While the SLP Settlement Motion makes it appear that the winter part-peak period is eliminated as well (at 6), we note that the illustrative rate design for A-6 included in Attachment A to the SLP Settlement includes a winter part-peak period for A-6. We therefore presume that a winter part-peak period will be included in the A-6 rate.

6.3.5. Other Small Commercial Settlement Elements

Various other elements of the SLP settlement appear to be non-controversial and widely agreed to by the SLP settling parties. Our review of the record of this proceeding indicates no reason why these elements of the SLP settlement should be rejected. These other elements of the SLP settlement are therefore approved as reasonable in light of the whole record, consistent with law, and in the public interest. These include:

- A suspension of the mandatory TOU and Peak Day Pricing (PDP) transition schedule for SLP customers until TOU rates with new peak periods are in effect for SLP customers.
    - A change to the PDP period applicable to SLP customers to 5 p.m. to 8 p.m., if such a period is adopted by the Commission in a different proceeding.
- CARE discount rates under the E-CARE rate schedule are maintained at a level that provides an average annual commercial CARE rate discount percentage that is equivalent to the annual average residential CARE discount.
- Threshold for eligibility for A-1 and A-6 is maintained at 75kW (or 150,000kWh/year).
- A 20% discount for food banks on the total bill, applied through distribution rates.
- A meet-and-confer schedule among some of the settling parties regarding the creation of a meaningful rate option for small businesses to manage energy costs, to be proposed in PG&E's next GRC Phase II.[120]

---

[120] Given that we order PG&E in this decision to develop more cost-based rates for its SLP customers, we expect this meet-and-confer will lead to concrete proposals that will be included in PG&E's next GRC Phase II application.

It appears that the settling parties included all of the parties that submitted testimony on SLP issues in this proceeding. The motion seeking approval of the SLP settlement states that the settlement "contains reasonable compromises after careful review and discussion by all interested parties of the wide variety of rate design proposals presented in the parties' prepared testimony, after incorporating appropriate revisions and updates, as well as information obtained during discovery."[121]

Given that there was substantial give-and-take between the settling parties during arm-length negotiation on these items, these elements of the SLP settlement are approved as reasonable in light of the whole record, consistent with law, and in the public interest. We direct PG&E to implement the elements of the SLP settlement as described above as soon as practicable following the issuance of a final Commission decision in this proceeding.

6.4. Economic Development Rate

On November 15, 2017, PG&E served a motion for adoption of a supplemental settlement on economic development rate design issues. PG&E's economic development rate (EDR) was adopted by the Commission in D.13-10-019. The EDR offers a 12% or 30% reduction in electric rates over a five year period with the aim of helping to bring new businesses to California and retain businesses that are present in California. Businesses currently eligible for EDR are those with loads of at least 200kW that have viable out-of-state location options, or are intending to cease operations in California altogether. The 30% EDR option is only available to eligible businesses that are located in cities and

---

[121] SLP Settlement Motion at 13.

counties with unemployment rates greater than 125% of California's annual average.[122]

EDR participation is capped at 200 megawatts (MW) and is due to be closed to new applicants upon the effective date of a decision in this proceeding, unless otherwise extended. The settlement seeks to extend eligibility for new EDR applications through 2020. The settlement also proposes to reduce the current enhanced EDR discount from 30% to 25%, modify EDR to increase the MW cap on participation, apply auditing requirements to certain large EDR customers, establish more granular rate reduction tiers, and make other changes to EDR to make the rate available to a greater range of businesses in areas with unemployment higher than the state average.[123]

While the settlement does not explicitly indicate that it is uncontested, it appears to be so given the lack of litigated EDR issues. We presume that the settlement is uncontested.

Our standard for reviewing uncontested settlements is set forth in Section 2. We must review the settlement to determine if it is reasonable in light of the whole record, consistent with law, and in the public interest. We reviewed the settlement's terms, and the ALJs assigned to this proceeding examined witnesses testifying on behalf of the settling parties on February 13, 2018. We find that the settlement should be approved for reasons including the following:

- While California unemployment rates have generally declined since the Commission adopted EDR in 2013, nine of the 10 counties in California with the highest unemployment rates

[122] EDR Settlement Motion at 2.

[123] EDR Settlement at 5-13.

as of December 2017, are entirely or partially in PG&E's service territory.[124] These are mostly in the Central Valley. EDR may therefore continue to help retain employment in these areas by lowering electricity costs for some businesses.

- The proposed reduction in the maximum EDR discount from 30% to 25% results in less impact on businesses competing with EDR participants.
- The proposed third-party auditing requirements for large EDR participants will help ensure attainment of energy efficiency, employment retention, and other public interest goals.
- The proposed modifications allowing smaller businesses to participate in EDR creates a more equitable program.
- The proposed cap on EDR participation, as well as the prohibition on EDR renewal for participants, ensures that the settlement will not result in disproportionate rate impacts on non-EDR customers.
- The expiration of EDR on December 31, 2020, or the final decision in PG&E's next GRC Phase II, whichever is later, will allow the Commission to revisit EDR in the near future and determine if it should continue.
- There is no law prohibiting the existence of PG&E's EDR; further, PU Code Section 740.4(a) provides that the Commission shall authorize public utilities to engage in programs to encourage economic development.

For reasons including those listed above, we find that the settlement is reasonable in light of the whole record, consistent with law, and in the public interest. We direct PG&E to implement the elements of the EDR settlement as

---

124 State of California, Employment Development Department's Labor Force and Unemployment Interactive Map <http://www.labormarketinfo.edd.ca.gov/data/interactive-labor-market-data-tools.html> (as of February 22, 2018). We acknowledge that PG&E only serves very small proportions of two of these counties: Siskiyou and Tulare.

soon as practicable following the issuance of a final Commission decision in this proceeding, with the clarifications described below.

6.4.1. Clarifications Required to the EDR Program

We order PG&E to make the following clarifications based on ambiguities in the settlement. PG&E testified that EDR MW allocations may not be reused once an EDR agreement with a customer expires at the end of five years.[125] However, the EDR settlement and EDR tariff attached to the settlement do not mention this prohibition. PG&E is ordered to modify its EDR tariff to clarify that once a certain amount of MW in its EDR cap is used for a five year agreement, and that agreement naturally terminates at the end of five years, those MW must be retired and may not be used to support other EDR applications. PG&E must track those EDR MW retirements and report on the total number of retired EDR MW in its next GRC Phase II application.

The EDR settlement proposes to allow a customer with A-1 and A-6 meters to aggregate with an A-10 meter used by the same customer to establish that customer's eligibility for EDR. These meters, according to PG&E's testimony, must be located in the same "physical contiguous space."[126] This term was not clearly defined during examination, and PG&E testified that meters "directly across the street" would "probably" qualify for EDR aggregation.[127] The proposed EDR tariff attached to the EDR settlement uses an entirely different

---

[125] Transcript at 420.

[126] Transcript at 426.

[127] Transcript at 426-427.

term, "a single Premises, as defined in PG&E's tariffs," to define the physical envelope in which the aggregated meters must be located.[128]

To avoid customer confusion and the potential for dashed expectations we order PG&E to clearly define in the EDR tariff sheet the physical envelope in which the aggregated EDR meters must be located. This definition must be detailed enough to allow a layperson to understand if their meters fall within the envelope or not. Cross-references to other portions of PG&E's tariffs are not acceptable.

Finally, in order to facilitate future review of this program, we direct PG&E to continue to file the annual EDR program performance reports adopted in D.13-10-019, and they must now include reporting on the third-party auditing outcomes described in the EDR settlement.

6.5. Residential Rates

On January 24, 2018, PG&E served a motion for adoption of a supplemental settlement agreement of residential rate design issues. The motion notes that much of PG&E's residential rate design over the next few years will be considered and decided in proceedings stemming from the Residential Rate Reform Order Instituting Rulemaking (the RROIR, R.12-06-013). Decisions emanating from that proceeding include D.15-07-001, which set rules for changing standard electric rates and directed consideration of various residential rate design proposals, including default TOU rates, to take place in a consolidated 2018 Rate Design Window proceeding (A.17-12-011, A.17-12-012, and A.17-12-013).

---

[128] EDR Settlement, Appendix 1, Sheet 1.

As a result, PG&E's proposals in this proceeding were primarily focused on updating other limited elements of residential rates, including:

1) Updates to gas and electric baseline quantities;
2) Revisions to its medical baseline program;
3) Updates to existing TOU rates as well as a proposal for a new residential TOU rate option; and
4) Updates to electric master meter discounts.

The residential rate design settlement resolves most of the issues raised in PG&E's application. Issues related to the electric master meter discount were not resolved by the settlement and are discussed subsequently in this decision. We consider the settlement to be uncontested given that the litigated issues were excluded from the settlement itself.

Our standard for reviewing uncontested settlements appears above in Section 2. We must review the settlement to determine if it is reasonable in light of the whole record, consistent with law, and in the public interest. We reviewed the settlement's terms, and the ALJs and Commissioner assigned to this proceeding examined witnesses testifying on behalf of the settling parties on February 27, 2018. We find that the settlement should be approved for reasons including the following:

- Changes to electric baseline quantities generally are justified given the change in PG&E's summer season from May-October to June-September.
- The baseline quantities were calculated using average usage data for regular and all-electric customers, and the settling parties' determination that 53.8% of average usage should be used to set baseline quantities of average usage is near the middle of the range authorized by statute (i.e., 50% - 60%).
- The settling parties' determination that 63.8% of average winter usage of all-electric customers should be used to set winter

baseline quantities for all-electric customers is near the middle of the range authorized by statute (i.e., 60% - 70%).

- Data provided by PG&E showed that increasing baseline quantities dramatically may have the unintended consequence of raising the price of baseline electricity, and increasing the bills of low-usage customers.
- PG&E's proposed baseline quantity calculations comply with the requirements of SB 711 as detailed below.
- Changes to Territory Q's boundaries and baseline quantities are justified given the climatic characteristics of the San Lorenzo Valley.
- Changes to the medical baseline outreach process will enhance public understanding and uptake of the program.
- Replacing the current customer enrollment limitation for the electric vehicle (EV) rate schedule with a usage limitation will help to facilitate wide-scale EV adoption in PG&E's territory, which aligns with broader state policy goals.
- Modification of the EV rate's peak and off-peak periods better align peak rates with peak marginal generation costs.

For reasons including those listed above, we find that the settlement is reasonable in light of the whole record, consistent with law, and in the public interest. We direct PG&E to implement the terms of the Residential Rate Design settlement as described above as soon as practicable following the issuance of a final Commission decision in this proceeding.

However, during examination of a panel representing the parties to the residential settlement on February 27, 2018, several troubling elements of the settlement were uncovered.

6.5.1. Additional Work Needed to Address Affordability in Residential Rate Design

While there are several areas of this GRC that touch upon affordability (i.e., the rate caps and floors considered in the MC/RA settlement, the shortening of summer months and slight increases to baselines in the residential settlement), it is clear from the record of this proceeding that additional work is needed to proactively address affordability in PG&E's residential rate design. In particular, responses to the Assigned Commissioner's Ruling on Electric Baselines of November 17, 2017 (Electric Baselines ACR), in this proceeding revealed that PG&E customers in the Central Valley experience greater levels of electric burden,[129] on average, than other PG&E customers.[130] PG&E's comments also acknowledged that affordability, bill volatility, and disconnection concerns for its customers were most pronounced in the Central Valley.[131] Yet the residential settlement does not directly acknowledge these problems for PG&E residential customers generally or how acutely they are felt in the Central Valley. During hearings, parties pointed to the availability of existing low-income assistance programs, while acknowledging that more granular data is needed to address issues of energy burden in the Central Valley. While we appreciate that proceeding R.12-06-013 is the main forum to discuss residential rate design issues

---

129 Defined as the percentage of a customer's annual income that is spent on annual electricity costs.

130 PG&E Comments to the Electric Baselines ACR at 14-15.

131 PG&E Comments to the Electric Baselines ACR at 10, 14 ("The Central Valley, which includes Territories P, R, S and W, has the highest electric bills and lowest incomes… A PG&E analysis of 2016 customer disconnection rates indicates that such baseline territories have a significantly higher disconnection rate: 6 percent in the Central Valley vs. 4 percent for cool and moderate climate regions. Furthermore, Kern County (Territory W) has one of the highest disconnection rates at 8 percent").

statewide, each investor-owned utility can and should acknowledge the importance of this issue in their individual rate design proceedings and propose steps to address it.

6.5.2. Failure of Residential Rate Design Settlement to Ensure Equitable Distribution of Baseline Quantities Based on "Microclimates"

Second, the residential settlement modified the baseline allowance and boundaries for baseline Territory Q only after receiving a formal request to do so from elected officials representing the County of Santa Cruz. Despite the fact that the modification is justified by the climatic conditions experienced by the San Lorenzo Valley, there was no effort made by PG&E to identify similarly situated "microclimates"[132] within PG&E's service territory.[133] As it is justified for the residents of the San Lorenzo Valley to receive a baseline allowance that aligns with the allowance enjoyed by other PG&E residential customers in areas with similar climatic conditions, fairness requires that all of PG&E's residential customers should receive the benefit of baseline quantities that reflect the climatic conditions of their location.

6.5.3. Concerns Regarding Usage Alerts for EV Owners

Third, while PG&E is making efforts in the residential settlement to make the EV rates more widely available to EV owners, there is little discussion of the tools available for EV owners to manage their usage and avoid enrollment on Schedule E-TOU-B. We therefore order PG&E to provide usage alerts to

---

132 Transcript at 684.

133 Transcript at 692.

Schedule EV customers similar to those provided to High Usage Surcharge customers so that they are aware of the risk of being transferred to Schedule E-TOU-B.

6.5.4. Opening of the EV-A Rate to Storage Customers with Less Than 12 Months of Usage Data

Finally, we note that the residential settlement includes a requirement that in order for a residential customer that installs storage to be eligible to take service on the EV-A rate, the installed capacity of the storage in kWh must be at least 0.05% of the customer's annual consumption from the previous 12 months for customers with more than 6,000 kWh of annual usage. The installed storage capacity for customers with 6,000 kWh or less of annual usage must be at least 2 kWh.

We do not object to minimum sizing requirements for energy storage systems, but we note that if this methodology was literally applied it could deny residential customers with less than 12 months of consumption history the ability to take service on the EV-A rate if they install energy storage. This could be a particular complication for customers that build and occupy new zero net energy (ZNE) homes.

To address this concern, PG&E must allow those customers with less than 12 months of consumption data to participate in the program. In lieu of estimating the customer's future usage, we set the minimum size of the installed energy storage system for those customers with less than 12 months of consumption data to be 2kWh. We choose this energy capacity threshold as it is the minimum required by the residential settlement for any residential customer participating in this program.

6.5.5. Further Work Required Before the Next PG&E GRC Phase II Proceeding

Further work on the issues described above is required before PG&E's application in its next GRC Phase II. We note that in response to questions from the assigned ALJs, Commissioner Peterman, and Commissioner Guzman Aceves on February 27, 2018, several parties to the residential settlement granted that further work such as that described below would be advisable.[134] Therefore, we order PG&E to do the following:

1) Following the recommendation of CforAT in its reply comments to the Electric Baselines ACR, it is necessary to determine what an essential amount of electricity is for PG&E residential customers, including those households in the Central Valley, instead of relying on the proxy of baseline quantities.[135] This type of information would be instrumental so that PG&E, stakeholders and the Commission can better evaluate whether PG&E's residential customers are meeting their basic electricity needs at a reasonable cost. PG&E is therefore ordered to develop a model of what constitutes essential use for its residential customers.[136] This model must be developed using research, both existing (information sources such as the Residential Appliance Saturation Survey and Experian data) and new direct customer surveys, to collect information on household size (in terms of both square footage and number of residents), building features (age, construction materials, insulation, etc.), and appliances (efficiency and usage) in order to better evaluate the essential electricity needs of PG&E's residential customers.

---

[134] Transcript at 713-727.

[135] CforAT Reply Comments to the Electric Baselines ACR at 6.

[136] We do not establish guidelines for how to define the term "essential use," but we recommend that PG&E and CforAT consider which indoor temperature should be used to benchmark a safe living environment when using an essential amount of electricity.

This model of essential usage must be able to specify the amount of essential usage in both summer and winter for residential customers separately in each of the hot climate zone (baseline territories R, S, W, and P), the warm climate zone (baseline territories X and Y), and the cool climate zone (baseline territories T, V, and Z). Separate analysis of Territory Q is unnecessary at this time. This model and its results must be submitted with PG&E's next GRC Phase II application. PG&E shall consult with parties to this proceeding, if a party expresses interest, when developing this research and model.

2) Families whose household income slightly exceeds the CARE threshold qualify to receive the FERA discounts - a 12% discount on their electricity bill. PG&E's testimony reveals that the FERA program, through lack of outreach or for other reasons, is not very highly subscribed.[137] PG&&E's subscription rate for the CARE program is far higher, and well above 50%. It is appropriate and necessary for PG&E to significantly increase its rate of FERA participation. Ultimately, PG&E should achieve a similar subscription level for FERA as for CARE. At this time, we require PG&E to make significant efforts to achieve a FERA subscription level of at least 50% before its next GRC Phase II filing. PG&E should particularly focus its efforts in the Central Valley, as suggested by PG&E and other parties to the residential rate design settlement.[138] PG&E should work with community-based organizations (CBOs) in the Central Valley to increase rates of FERA participation. PG&E should hold one or more workshops in the Central Valley in 2018 with local CBOs toward this effort. PG&E shall report to Energy Division by December 31, 2018 and December 31, 2019 on its progress to increase FERA subscription.

3) In order to provide the Commission with the opportunity to consider new ways of defining baseline territories that prioritize

---

[137] Transcript at 724. CforAT notes that the maximum FERA enrollment statewide is only 14% or 15% (Transcript at 727-728).

[138] Transcript at 724-727.

simplicity and fairness for customers, PG&E must propose the following revisions to its electric baseline territory boundaries and allowances in its next GRC Phase II application:

a) PG&E must analyze the climatic records of each National Oceanic and Atmospheric Administration – National Weather Service (NWS) station with 30 year average summer maximum temperature and winter minimum temperature within its territory. PG&E must then determine if customers in the vicinity of each weather station[139] receive appropriate amounts of baseline electricity allocations given the climatic conditions experienced by each group of customers. PG&E shall determine this appropriateness by comparing the climatic condition of the customers (as revealed by the NWS weather station data) to the average climatic condition of the baseline territory in which the customers are located and all other existing PG&E baseline territories. If PG&E finds that the climatic conditions of the customers are a better match for a different baseline territory than their current territory, then PG&E must assign that group of customers to the baseline territory that is a better match. PG&E must conduct this analysis separately for winter and summer climatic conditions, and match each group of customers with its best fit for each season, even if that results in different baseline territories for each season. In effect, this ordered revision will replicate for all residential customers in PG&E's territory the analysis done in the 2017 GRC Phase II for customers in the San Lorenzo Valley. PG&E shall ensure that all of its residential customers are afforded the same consideration granted to customers in the San Lorenzo Valley in this proceeding.

[139] PG&E must assign each of its residential customers to a NWS weather station when completing this analysis. We understand that PG&E assigns each of its residential customers to a baseline territory depending on the customer's county of residence, elevation and latitude/longitude coordinates. This analysis will require PG&E to disregard those existing boundaries and instead assign their residential customers to NWS stations with 30-year data in the vicinity of the customers.

b) PG&E must also provide a simplified baseline territory system for our consideration whereby the number of summer and winter baseline territories in PG&E territory is limited to no more than three for each season. Each territory created shall be based on climatic conditions with specifically described characteristics of PG&E's choice (e.g., average summer maximum temperatures above 90 degrees). PG&E shall then assign its residential customers to the new territories depending on their local climatic conditions (as revealed by NWS weather station data).

c) PG&E may also propose to maintain all baseline territorial boundaries as they exist as of the effective date of this decision.

New electric baseline allowances must be calculated under each of these revisions and submitted with the PG&E's next GRC Phase II application. Maps showing the results of the revisions must also be submitted.

4) As discussed above, PG&E must provide usage alerts to Schedule EV customers similar to those provided to High Usage Surcharge customers so that they are aware of the risk of being transferred to Schedule E-TOU-B.

5) As discussed above, PG&E must allow those energy storage residential customers with less than 12 months of consumption data to opt in to the EVA rate. In lieu of estimating the customer's future usage, we set the minimum size of the installed energy storage system for those customers with less than 12 months of consumption data to be 2 kWh.

6.5.6. Compliance with Senate Bill 711

Senate Bill (SB) 711 (Hill, 2017) amended Public Utilities Code Section 739 and requires the Commission to make efforts to minimize bill volatility for residential customers, including all-electric customers, by explicitly authorizing the Commission to make certain changes to gas and electric baselines.[140]

The Electric Baselines ACR asked parties to examine a variety of baseline scenarios and provide their comments on whether the baseline scenarios outlined in the ACR would best minimize bill volatility for residential customers, including all-electric customers.

Comments on this issue were received from PG&E, SCE, and CforAT. While SCE notes that some of the ACR's scenarios produce less bill volatility than others,[141] SCE and PG&E agreed that bill volatility was primarily driven by climate-based month-to-month changes in customer demand rather than the baseline amount of energy at issue.[142] CforAT noted that while efforts to increase baseline quantities may reduce bill volatility for some high-usage customers, doing so may increase the price of baseline quantities of energy and end up increasing the overall bills of low-usage customers.[143]

Summarizing its view on our ability to execute SB 711's intent, SCE notes that "increasing baseline allocations and/or having sufficiently long seasons

---

140 Public Utilities Code Section 739(a)(1).

141 SCE Comments to Electric Baselines ACR at 4-6.

142 SCE Comments to the Electric Baselines ACR at 6-7 (noting that increased baseline quantities only help to "slightly soften" the impact of higher month-to-month usage) and 12 ("bill volatility is largely the result of changes in usage driven by weather"); PG&E Comments to the Electric Baselines ACR at 10 ("[e]lectric bill volatility is created by seasonal changes in the usage of electricity in both the summer and winter").

143 CforAT Comments to the Electric Baselines ACR at 9-10 (recommending that Commission use highly targeted efforts to reduce bill volatility rather than changing baseline quantities in such a way that baseline energy becomes more expensive).

seems to result in less bill volatility, though not to a significant degree."[144] PG&E argues that baseline changes will not significantly reduce bill volatility, and that more direct means of reducing volatility are to reduce rate differentials and implement a fixed charge.[145]

In light of the comments made by the parties on this issue, we find that adjusting baseline quantities is not the best way to make efforts to address bill volatility at this time, given that the impacts are expected to be small and that the price of baseline energy would be increased as a result. The record demonstrates that there are other mechanisms (e.g., CARE, FERA, and energy efficiency programs) that can, and should, be used to address bill volatility that would not have the effect of increasing the price of baseline energy.

6.6. Standby, Medium and Large Commercial Rates

On January 31, 2018, PG&E served its motion for adoption of the standby and medium and large light and power rate design supplemental settlement agreement (the MLLP settlement). The parties to the settlement are SEIA, CALSSA, EUF, CLECA, CMTA, EPUC, FEA, CTP, and PG&E. CIPA filed a motion on March 2, 2018 objecting to certain provisions of the settlement, and SEIA and CALSSA each litigated positions on specific rates for A-10, E-19, E-20 customers that install customer-sited energy storage devices. The MLLP settlement is contested on these issues. However, much of the MLLP settlement is uncontested, and for the sake of clarity we review those terms of the settlement using our standard of review for uncontested settlements. The contested issues

---

144 SCE Comments to the Electric Baselines ACR at 12.

145 PG&E Comments to the Electric Baselines ACR at 12.

raised by CIPA, SEIA, CALSSA are considered later in this decision and do not impact our discussion of the MLLP settlement generally.

The MLLP settlement concerns rate design for customers taking service on several PG&E rate schedules: A-10, E-19, E-20, and S (standby). It also concerns customers taking service on variants of these schedules such as E-19V and E-20R. These customers have accounts with demand in excess of 75 kW or usage in excess of 150,000 kWh per year. Generally, we refer to these customers as medium and large customers or MLLP customers.

Our standard for reviewing uncontested settlements appears above in Section 2. We must review the settlement to determine if it is reasonable in light of the whole record, consistent with law, and in the public interest. We reviewed the settlement's terms, and the ALJs assigned to this proceeding examined witnesses testifying on behalf of the settling parties on March 2, 2018. We find that the settlement may be approved, if MLLP settling parties accept our proposed modifications, for reasons including the following:

- Delaying the mandatory conversion of medium and large customers to new peak periods will give PG&E time to fully educate these customers about the peak period changes and strategies for reducing energy consumption during peak periods.
- The generation demand charges, energy charges and customer charges for each rate schedule proposed by the settlement are reasonable in light of the adjustments customers will need to make to the new TOU peak periods.
- The proposed Food Bank Rate is reasonable and in compliance with the law.

The MLLP settlement as served and filed is not reasonable in its entirety. Consistent with our standard of review for uncontested settlements, we find that the settlement's distribution demand charge rate design is unreasonable in light of the whole record, the law, and the public interest. The MLLP settlement's distribution demand charge rate design is also not in accord with previous Commission decisions, including the decision in the recent SDG&E GRC Phase II proceeding (D.17-08-030).

Pursuant to Rule 12.4 of the Commission's Rules of Practice and Procedure, we reject the MLLP settlement and propose alternative terms to the parties to the MLLP settlement that are acceptable to the Commission. In order to allow the MLLP settling parties reasonable time within which to elect to accept these alternative terms or to request other relief, we seek comments to this proposed decision by parties to the MLLP settlement on our proposed modification to the MLLP settlement. If the parties approve of our proposed modifications to the MLLP settlement's rate design as described below, then we will adopt the MLLP settlement as modified by this proposed decision.

If a party or parties to the MLLP settlement comment on the proposed decision and indicate that they do not approve of our proposed modification to distribution demand charge rate design, then we will reject the MLLP settlement in its entirety and assign consideration of the reasonableness of PG&E's MLLP rate design to a later phase of this proceeding where a future decision will settle all MLLP rate design issues as litigated issues. This will allow us to hold hearings on the underlying issues and allow parties time to renegotiate the MLLP settlement under Rule 12.4.

6.6.1. Changes to Distribution Demand Charges as Proposed by the MLLP Settlement

The MLLP settling parties ask the Commission to approve a rate design for A-10, E-19, and E-20 customers that substantially modifies their existing distribution demand charges. A demand charge is a $/kW charge that is used to collect revenue from customers that is then used to meet the revenue requirement of the utility. Demand charges differ from energy charges in that they are assessed using the maximum kW demand of a customer during a certain interval, rather than the total amount of energy used by a customer.

A table comparing the proposed summer distribution demand charges in $/kW for A-10, E-19, and E-20 customers with their existing summer distribution demand charges appears below.

Rate Schedule	Current Peak Demand Charge	Proposed Peak Demand Charge	Current Part-Peak Demand Charge	Proposed Part-Peak Demand Charge	Current Maximum Demand Charge	Proposed Maximum Demand Charge
A-10S	N/A	N/A	N/A	N/A	$6.18	$4.07
A-10P	N/A	N/A	N/A	N/A	$5.90	$3.88
A-10T	N/A	N/A	N/A	N/A	$1.12	$1.32
E-19S[146]	$6.01	$5.91	$2.06	$1.04	$10.37	$12.25
E-19S-R	$1.50	$1.48	$0.51	$0.26	$10.37	$12.25
E-19P[147]	$5.31	$5.51	$1.78	$0.91	$7.21	$8.82
E-19P-R	$1.33	$1.38	$0.44	$0.23	$7.21	$8.82
E-19T[148]	$0	$0	$0	$0	$1.94	$2.63
E-19T-R	$0	$0	$0	$0	$1.94	$2.63
E-20S	$5.81	$4.97	$1.99	$1.21	$9.90	$11.72
E-20S-R	$1.45	$1.24	$0.50	$0.30	$9.90	$11.72
E-20P	$5.82	$4.89	$1.95	$0.84	$7.55	$9.86

[146] Includes E-19S-V

[147] Includes E-19P-V

[148] Includes E-19T-V

Rate Schedule	Current Peak Demand Charge	Proposed Peak Demand Charge	Current Part-Peak Demand Charge	Proposed Part-Peak Demand Charge	Current Maximum Demand Charge	Proposed Maximum Demand Charge
E-20P-R	$1.46	$1.22	$0.49	$0.21	$7.55	$9.86
E-20T	$0	$0	$0	$0	$0.77	$0.92
E-20T-R	$0	$0	$0	$0	$0.77	$0.92

In terms of the difference in revenue collected from these demand charges, we restate our analysis on the distinction between the current distribution revenue collected from these customers and the revenue PG&E proposes to collect through the MLLP settlement rates, as described in Attachment 2 to PG&E-39.

Rate Schedule[149]	Current Percentage of Distribution Revenue Collected Through Peak and Part-Peak Demand Charges	Proposed Percentage of Distribution Revenue Collected Through Peak and Part-Peak Demand Charges
E-19-S	25.8%	15%
E-19-P	29.2%	17.3%
E-20-S	27.2%	14.7%
E-20-P	32.2%	15.7%

6.6.2. Reasons for Our Proposed Changes to the Distribution Demand Charges

The drivers for these changes in the calculation of the demand charges are not spelled out by the motion to adopt the MLLP settlement, but PG&E

[149] A-10, E-19-T, and E-20-T rates are not included as they do not currently face peak or part-peak demand charges for distribution.

Exhibit 39 describes the cost basis used by PG&E and the MLLP settlement to determine the distribution demand charge rate design for A-10, E-19, and E-20 customers. In that exhibit, PG&E explains that its cost basis for distribution charges is developed based on two main categories of costs: MDCC and MCAC.[150] The customer charge for MLLP customers is based on MCAC.[151]

PG&E's MDCC is constituted by three components: primary distribution capacity cost (PDCC), new business primary distribution capacity cost (NBPDCC), and secondary distribution capacity cost.[152] In its exhibit, PG&E asserts that only PDCC are related to meeting distribution peak demand, while NBPDCC and secondary distribution costs are incurred to meet the non-coincident demand of customers.[153]

PG&E argues that because only PDCC are incurred to meet peak demand, only PDCC should be subject to collection using time-differentiated (i.e., peak and part-peak) demand charges.[154] PG&E states that the NBPDCC and secondary distribution capacity costs should be recovered through non-coincident demand charges.[155]

We apply our standard of review for settlements to determine whether the distribution demand charge rate design proposed by the MLLP settlement is reasonable in light of the whole record, consistent with law, and in the public

---

150 PG&E-39 at 2.

151 PG&E-39 at 3.

152 PG&E-39 at 3.

153 PG&E-39 at 3.

154 PG&E-39 at 3-5.

155 PG&E-39 at 4. *See also* PG&E-8 at 6-4, fn 3.

interest.[156] As we stated in section 2, we are under no duty to accept unreasonable settlements in spite of our long-standing policy to favor settlements of disputes in our proceeding. We find that the MLLP settlement's distribution demand charge rate design is unreasonable in light of the whole record and the public interest, as described below, and therefore should be modified. As noted above, we seek comments from the MLLP settling parties that indicate their approval or disapproval of our approach to distribution demand charge rate design.[157]

6.6.2.1. The MLLP Settlement's Distribution Demand Charge Rate Design is Not in the Public Interest or in Accord with State Policy

We incorporate by reference our findings in section 6.2 that the demand charge rate designs appearing in the various settlements in this proceeding, including the MLLP settlement, are not in accord with state policy and our previous decisions, for the following reasons:

1) They are not in accord with state energy policy to encourage optimal usage of renewable energy resources.
2) They fail to provide a menu of rate options to allow customers to avoid marginal utility costs.
3) They impose costs on society by encouraging GHG emissions.

---

[156] Commission Rules of Practice and Procedure, Rule 12.1(d). The Rule states that a settlement must be "reasonable" according to three criteria: the record, the law, and the public interest. The Rule's use of the conjunctive "and" when describing the criteria means that the failure of a settlement to be reasonable on *any* of those grounds will lead us to reject the settlement. In other words, a settlement must meet all three criteria to be acceptable.

[157] Should any of the MLLP settling parties disapprove, we will reject the MLLP settlement in its entirety and hold hearings on all MLLP rate design issues in a later phase of this proceeding.

4) They overcharge customers for off-peak energy usage.

Because the MLLP settlement establishes rates for PG&E's most sophisticated customers that can respond quickly to rate signals,[158] the countervailing concern of customer acceptance of new TOU periods does not apply as forcefully here as it does with respect to the other settlements. In light of the reduced need to promote customer acceptance of new TOU periods for these customers, we find that the MLLP settlement's distribution demand charge rate design is unreasonable as it does not adequately promote the public interest.

6.6.2.2. The MLLP Settlement's Distribution Demand Charge Rate Design Is Not In Accord with the Commission's Historic Rate Design Principles

Furthermore, we find that the MLLP settlement's distribution demand charge rate design is unreasonable when evaluating it against the historic rate design principles used by the Commission. We fully discussed these principles and our preferred approach to rate design previously in this decision in Sections 3 and 6. As a reminder, we noted that the Commission previously articulated its rate design principles as follows:

1) Low income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost;
2) Rates should be based on marginal cost;
3) Rates should be based on cost-causation principles;
4) Rates should encourage conservation and energy efficiency;

---

[158] PG&E Reply Brief at 18.

5) Rates should encourage reduction of both coincident and non-coincident peak demand;

6) Rates should be stable and understandable and provide stability, simplicity and customer choice;

7) Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals;

8) Incentives should be explicit and transparent;

9) Rates should encourage economically efficient decision-making; and

10) Transitions to the new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.[159]

We recently applied these principles to the question of reasonable distribution demand charges in SDG&E's most recent GRC Phase II proceeding. Generally, we held in D.17-08-030 that the rate design principles as a whole justified reducing the amount of distribution revenue collected through SDG&E's non-coincident distribution demand charges for its MLLP customers from 65% to 39%.[160] We also reasoned that SDG&E's proposal to increase the proportion of distribution costs recovered with non-coincident demand charges to 70% was not justified in light of recent Commission decisions that moved toward greater use of TOU and other time-varying rates to better reflect cost causation, avoid cross subsidies, encourage efficiency, and otherwise incent customer behavior that

[159] D.17-08-030 at 30-31; D.17-01-006 at 37; D.15-07-001 at 27-28 (noting that the principles were developed after receiving extensive input from parties).

[160] D.17-08-030 at 45.

would help meet state policy goals.[161] Specifically, the decision stated that rejecting SDG&E's proposal and significantly reducing the proportion of SDG&E's distribution costs collected through non-coincident demand charges is "consistent with our rate design principles that rates should be based on marginal cost…".[162]

We reiterate the findings of D.17-08-030 here. Heavy reliance on non-coincident demand charges is generally disfavored by our historic rate design principles because non-coincident demand charges do not reflect cost causation for primary distribution, transmission, or generation capacity costs.[163] Additionally, as described in Section 6.2, rate designs that heavily rely on non-coincident demand charges also promote inefficient use of energy contrary to state policy goals encouraging economically efficient and socially beneficial energy usage. Therefore, the proposal by PG&E and the MLLP settlement to collect between 70% and 100% of non-customer access-related distribution revenue for MLLP customers through non-coincident demand charges is unreasonable in light of our historic rate design principles.

6.6.2.3. The MLLP Settlement's Distribution Demand Charge Rate Design Is Unreasonable in Light of the Whole Record of this Proceeding

PG&E states in its testimony that "the distribution *system* must be sized to meet the demand of PG&E's system…" (emphasis added).[164] PG&E does not

[161] D.17-08-030 at 45-47.

[162] D.17-08-030 at 47.

[163] D.17-08-030, Finding of Fact 25.

[164] PG&E-39 at 4.

distinguish between the elements of its system that receive (or do not receive) PDCC investments, NBPDCC investments, and secondary investments when making this statement.

Exhibits CPUC-2 and PG&E-9 evidence how PG&E's distribution system as a whole tends to experience peak demands during the 4 p.m. to 9 p.m. period during the summer.[165] Regardless of whether the individual load of a new business customer dictates the capacity of a single new business primary distribution capacity investment, the sum of those investments across PG&E's territory will tend to peak between 4 p.m. and 9 p.m. during the summer.[166] Or as we held in a previous decision, PG&E's "need for additional… primary distribution capacity [is] driven by customers' coincident peak demand."[167]

PG&E's witnesses testifying on behalf of the MLLP settlement also indicated that, upon examination of the evidence in CPUC-2 that most PG&E distribution circuits peak between 4 p.m. and 9 p.m., they could not distinguish between circuits that received PDCC- or NBPDCC-related investments when assessing the distribution of circuit peaks.[168]

---

165 CPUC-2 at 2; PG&E-9, Chapter 12 at 15, showing that distribution peaks in most of PG&E's 19 geographic divisions tend to occur between 4 p.m. and 9 p.m. during the months of June – September. The weighted average of all 19 division areas show 65% of distribution peaks occur between 4 p.m. and 9 p.m. during PG&E proposed summer period, and 19% of distribution peaks occur during the part peak periods of 2 p.m. to 4 p.m. and 9 p.m. to 11 p.m. in the summer.

166 Transcript at 1031. *See also* SEIA Reply Brief at 3, fn 5 ("most of PG&E's marginal distribution costs fall within the settled 4 p.m. to 9 p.m. peak period").

167 D.14-12-080, Finding of Fact 8.

168 Transcript at 1030-1033.

As stated above, PG&E argues in exhibit PG&E-39 that it is appropriate to recover NBPDCC through non-coincident demand charges due to the individual customer demands driving those investments. CLECA agrees, claiming that because NBPDCC are a "function of customer access" they are not costs that are incurred on a TOU basis and therefore not suitable for recovery through time-related charges.[169]

However, NBPDCC are indisputably marginal costs that, as revealed through the record of this proceeding, are as likely to be spent on circuits that peak during the 4 p.m. to 9 p.m. peak period as any other marginal distribution investment made by PG&E. And as we stated in D.17-01-006, "[t]he objective of using marginal distribution costs and timing of distribution system peaks in determining Base TOU periods is to better align time-differentiated rates with time-differentiated marginal costs."[170] It would be illogical to create a TOU peak period based on marginal costs and then not assign time-based marginal cost recovery to those peak periods.

It is also worth noting that in its prepared testimony, PG&E agrees with the general principle that TOU peak periods should include consideration of system-wide distribution peaks and should incent customers to shift their loads away from high-cost hours to lower-cost hours, in response to "actual marginal costs."[171] They also cite previous Commission decisions when they state "for decades, the [Commission] has used demand charges to collect capacity-related costs, since doing so is consistent with cost-based rate design… Rate design

[169] CLECA Opening Brief at 9, fn 29.

[170] D.17-01-006 at 28.

[171] PG&E-9 at 12-2.

based on marginal costs establishes demand charges (in units of dollars per kW) for these services."[172]

We agree and find that to be consistent with our rate design principles and previous Commission decisions, actual distribution capacity-related marginal costs (excluding MCAC) attributable to MLLP customers should be reflected in peak and part-peak distribution rates experienced by those customers. To find otherwise would not be reasonable in light of the whole record of this proceeding, our rate design principles, or previous Commission decisions.

6.6.3. Proposed Alternative Rate Design for Distribution Demand Charges for MLLP Customers

As the MLLP settlement's distribution demand charge rate design is unreasonable in light of the whole record and the public interest, we propose an alternative distribution demand charge rate design for PG&E's MLLP customers. We seek comments to this proposed decision by the MLLP settling parties on whether they approve or disapprove of the alternative rate design described below.

Based on the evidentiary record, we find that all of PG&E's marginal distribution capacity costs (excluding MCAC) that PG&E attributes to its MLLP customers should be recovered from the MLLP customers with time-dependent distribution rates proportionate to the percentage of PG&E's distribution circuits that experience peaks during the peak and part-peak periods.[173]

---

172 PG&E-8 at 6-8, citing D.15-08-005 and D.11-12-053.

173 Nothing in this decision prevents, or should be read as discouraging, PG&E from exploring and proposing distribution rates that reflect the costs faced by particular circuits. For example, PG&E's testimony is that different planning areas experience different distribution circuit

Footnote continued on next page

Because 65% of PG&E's distribution circuits tend to peak during the 4 p.m. to 9 p.m. period during the summer,[174] 65% of the marginal distribution capacity costs (excluding MCAC) attributable to a MLLP customer class should be collected through summer peak demand charges for that class.[175]

Because 19% of PG&E's distribution circuits tend to peak during the proposed summer part-peak period of 2 p.m. to 4 p.m. and 9 p.m. to 11 p.m., 19% of the marginal distribution capacity costs (excluding MCAC) attributable to a MLLP customer class should be collected through summer part-peak demand charges for that class.

The remaining 16% of marginal distribution capacity costs (excluding MCAC) attributable to a MLLP customer class should be collected through non-coincident demand charges for that class.

The MLLP settlement is unreasonable to the extent it does not comport with this methodology.[176] All cost categories listed in exhibit CPUC-1 for each

---

peaks. PG&E may wish to offer various distribution rate schemes in the future that account for these geographic differences. As those kinds of rates are not before us, we do not opine on their merits. We are faced with utility-wide rates at this time, and so we seek to align utility-wide costs and utility-wide peak demand with those rate structures. We note that this means that A-10-T, E-19-T, and E-20-T customers may not face peak or part-peak summer demand charges as PG&E does not allocate them responsibility for non-MCAC marginal distribution costs.

[174] PG&E-9, Chapter 12 at 15, Table 12-5. *See also* CPUC-2 at 2.

[175] Demand charges are PG&E's favored rate vehicle to recover these types of costs as revealed by their statement that "rates that are well aligned with cost recover [distribution] capacity costs through demand charges on a dollar per kW basis" (PG&E-39 at 4). PG&E does not distinguish between the three kinds of marginal distribution capacity costs when making this statement. *See also* D.15-08-005 Conclusion of Law 8 ("Demand charges fairly allocate infrastructure costs to customers"), which also does not distinguish between primary and new business primary capacity costs.

[176] To illustrate how this will affect the proposed MLLP settlement rates, setting the cost basis for summer peak demand charges in this way would mean that 65% of the $144,934,730 of

Footnote continued on next page

class should be considered the marginal costs attributable to each MLLP customer class. The billing determinants listed in the workpaper supporting exhibit PG&E-39 should be used to calculate the illustrative demand charge revenue required to collect the marginal distribution costs attributable to each MLLP customer class. As this workpaper does not include estimates of peak or part-peak kW demand for A-10-P or A-10-S customers, PG&E must prepare those estimates to complete the calculations.

Parties to the MLLP settlement are requested to comment on our proposed rate design in this proposed decision and indicate their approval or disapproval of our approach. If all commenting parties approve, we will consider the settlement modified and approve the MLLP settlement as modified by our proposed rate design. If any MLLP settling party disapproves of our approach in its comments then the MLLP settlement as a whole will be rejected and MLLP rate design in its entirety will be litigated in a future phase of this proceeding.

6.6.4. Reasonableness of Our Rate Design Approach

While we recognize that the MLLP settlement attempted to balance the proper marginal cost basis for rates with the expected bill impacts resulting from TOU changes approved earlier in this decision,[177] we find that the MLLP

---

marginal distribution costs allocated to E-19-S customers per exhibit CPUC-1 (or $94.2 million) would be recovered through a summer peak demand charge for E-19-S customers. Dividing $94.2 million by the 10,303,800 total peak summer demand kW forecasted for E-19-S customers (per the PG&E workpaper supporting exhibit PG&E-39) results in a summer peak demand charge for E-19-S customers of $9.14/kW. Contrast this with the illustrative peak summer demand charge for E-19-S customers in the MLLP settlement of $5.91/kW.

[177] *See, e.g.*, CLECA Opening Brief at 4-7.

settlement strays too far from marginal cost-based ratemaking principles by excluding recovery of NBPDCC in time-based distribution charges.

Further, the revisions we propose to the MLLP distribution demand charges still allow PG&E to collect the majority of their distribution demand charge revenue through non-coincident demand charges. We therefore find that these adjustments align more with the utility's perspective in this proceeding than in the recent SDG&E GRC Phase II proceeding where we allowed SDG&E to only collect approximately 39% of its distribution demand charge revenue through non-coincident demand charges. The lower non-coincident demand charge percentage assigned to SDG&E may largely be due to SDG&E's practice of identifying a separate marginal cost component for its substations. We find that this practice improves the accuracy of marginal distribution capacity cost estimates, and direct PG&E to identify marginal substation capacity costs as a separate component of its marginal distribution capacity costs in its next GRC Phase II application.

We also find that the revisions we propose to the MLLP rates are reasonable because the share of distribution revenue PG&E would collect through non-coincident demand charges closely mirrors the share they currently collect through the non-coincident demand charges that we found to be reasonable in our last PG&E GRC Phase II decision. This addresses the concern raised by some parties that our decision in the SDG&E GRC Phase II proceeding should not be used as a basis for judging the reasonableness PG&E rate designs.[178] The table below illustrates the similarities between PG&E's current rate design for recovery of distribution revenue and the one we propose.[179]

Rate Schedule	Current % of Distribution Revenue Collected Through Non-Coincident Demand Charges	MLLP Settlement Proposed % of Distribution Revenue Collected Through Non-Coincident Demand Charges	Modified MLLP Settlement % of Distribution Revenue Collected Through Non-Coincident Demand Charges
E-19-S	64.1%	74.6%	64.2%
E-19-P	59.5%	70.8%	58.5%
E-20-S	66.8%	78.9%	66.0%
E-20-P	62.1%	79.5%	65.1%

6.6.5. Failure of the MLLP Settlement to Account for the Interests of A-10 and E-19V Customers

We have a specific concern about the representation of customers on A-10 and E-19V in the MLLP settlement. No party other than PG&E proposed rates for A-10, and the settlement A-10 distribution rates are identical to the rates originally proposed by PG&E.[180]

We note, in contrast, that some of the settling parties, notably CLECA and FEA, made specific proposals for E-19 and E-20 rate design in their testimony,[181]

---

[178] CLECA Opening Brief at 8-10.

[179] PG&E should not interpret this discussion as a finding that it would be reasonable to maintain the current proportion of distribution revenue recovered in non-coincident demand charges going forward. It remains CPUC policy, as articulated in D.17-08-030, to reduce dependence on non-coincident demand charges generally.

[180] PG&E-39, Attachment 1 at Atch1-1; Transcript at 1044.

[181] CLECA-1 at 100-111; FEA-1 at 14-18.

but general A-10 rate design was given passing mention only by EUF[182] and SEIA.[183] While SEIA did propose rate designs for A-10 solar and A-10 storage customers, SEIA's witness stated that SEIA "had a position on Option R rates for A-10 in our testimony. So you know, we were certainly negotiating in the settlement on behalf of A-10 customers who install solar."[184] SEIA was not, apparently, negotiating on behalf of A-10 customers without solar or storage systems.

In hearings, CLECA's witness testified concerning A-10 rate design and stated CLECA "was focused on the most complex rates on the system, which are the E-20 and the E-19, the so-called, the closest to being pure cost of service."[185]

We infer, based on the above, that A-10 customers (other than solar and storage customers) were not actively represented by the settling parties, and that the MLLP settlement A-10 rates were not based on a compromise among the various parties but, at least for distribution rates, simply reflected PG&E's opening position.

We are concerned by this approach to ratemaking for the A-10 class and remind PG&E that they are ordered to propose rates for the A-10 class in its next GRC Phase II proceeding that more closely hew to cost-causation than the rates approved in this decision. PG&E must demonstrate in their ultimate rate proposal for A-10 customers in their next GRC Phase II proceeding (whether through settlement or litigated position), that the interests of A-10 customers

[182] EUF-1 at 12.

[183] SEIA-1 at 39.

[184] Transcript at 1044.

[185] Transcript at 1052 – 1053.

were represented in an arms-length fashion in the development of new A-10 rates.

6.7. Agricultural Rates

On March 30, 2018, PG&E served a motion to adopt a supplemental settlement agreement on agricultural rate design issues (Ag rates settlement). The parties to the Ag rates settlement are PG&E, CFBF, and AECA. These are the only parties that filed testimony on agricultural rate design issues in this proceeding. We therefore regard the settlement as uncontested.

The Ag rates settlement generally establishes a 5 p.m. to 8 p.m. peak period for agricultural customers, as well as establishing a four month summer season and timeline for mandatory conversion of agricultural customers to the new TOU periods. We discussed the 5 p.m. to 8 p.m. peak period earlier in this decision and approved it for agricultural customers.

Our standard for reviewing uncontested settlements appears above in Section 2. We must review the Ag rates settlement to determine if it is reasonable in light of the whole record, consistent with law, and in the public interest. We reviewed the Ag rates settlement's terms, and an ALJ assigned to this proceeding examined witnesses testifying on behalf of the settling parties on April 10, 2018. We find that the Ag rates settlement should be approved for reasons including the following:

- It significantly simplifies the rate schedules available to agricultural customers and includes specific provisions for customer outreach and education on the new TOU periods.
- It delays implementation of the new TOU periods to March 2020 and 2021 to account for the seasonal nature of agricultural operations and allow for post-harvest education on the new TOU periods and rates before the commencement of summer season rates.

- Mitigation measures for those agricultural customers most affected by the new TOU rates will be considered in PG&E's 2019 Rate Design Window (RDW) proceeding.
- If mitigation measures are not developed in time for the mandatory implementation of new TOU rates in March 2021, the most affected agricultural customers will be allowed to stay on legacy TOU periods and rates, as defined by the Agricultural TOU settlement, until March 2022.
- The Ag rates settlement includes a rate option for agricultural customers that allows for two days per week of off-peak usage to accord with agricultural operational needs.

For reasons including those listed above, we find that the Ag rates settlement is reasonable in light of the whole record, consistent with law, and in the public interest. We direct PG&E to implement the terms of the Ag rates settlement as soon as practicable following the issuance of a final Commission decision in this proceeding.

We note, however, that the significant reductions in price differentials between peak and off-peak periods and the lack of time-differentiation for distribution charges on any of the default agricultural rates is not in accord with Commission policy and previous decisions. While we find that the Ag rates settlement is reasonable in spite of that dissonance,[186] PG&E must propose in its next GRC Phase II application agricultural rates (along with all other non-residential TOU rates) that better reflect time-differentiation of marginal distribution costs, and contain peak-to-off-peak price differentials that encourage

[186] Owing mainly to the persuasiveness of the argument made by settling parties that agricultural customers have characteristics that require a "soft landing" with respect to a transition to new TOU peak period definitions (Transcript at 1210, 1220).

agricultural customers to invest in energy management technology and practices that allow them to respond to peak price signals.

6.8. Legacy Solar Customer Rates

On January 22, 2018, PG&E served a motion to adopt a supplemental settlement agreement on TOU rates for grandfathered solar customers (TOU settlement).[187] The parties to the TOU settlement are SEIA, CALSSA, EUF, Energy Freedom Coalition of America, SBUA, CLECA, EPUC, and PG&E. The County of San Joaquin and the County of Santa Clara served joint comments on the motion on February 22, 2018. They state that they actively participated in settlement discussions but did not join the settlement.[188] We therefore regard the TOU settlement as contested.

On March 28, 2018, PG&E served a motion to adopt a supplemental settlement agreement on TOU rates for legacy solar agricultural customers (Ag TOU settlement). The parties to this supplemental settlement are PG&E, CALSSA, AECA, and CFBF. We regard the Ag TOU settlement as uncontested.

The TOU settlement and Ag TOU settlement (TOU settlements) seek to apply the requirements of D.17-01-006, which set out guidelines for how to apply changes in TOU peak periods to utility customers with existing customer-sited renewable generation systems. These customers with existing systems were to be given the opportunity to remain on "legacy" TOU rates when new TOU peak

---

[187] We are reluctant to use the term "grandfathering" in this decision to describe the rates and TOU periods applicable to legacy solar customers given the etymology of the term. Therefore we will refer to the Supplemental Settlement Agreement on Time of Use Rates for Grandfathered Solar Customers served on January 22, 2018 as the "TOU settlement." Those customers that are eligible for "grandfathering" under D.17-01-006 are generally referred to as "legacy" solar customers in this decision.

[188] TOU Settlement Comments of County of San Joaquin and County of Santa Clara at 8.

periods were applied to other customers. The decision deferred consideration of the actual rate design to be used for legacy TOU customers. D.17-01-006 held that other changes in rate design, including allocating marginal costs to TOU periods and setting specific rate levels, were to be litigated in utility-specific rate proceedings, such as the instant proceeding.[189]

The TOU settlements generally seek to levelize the peak to part-peak prices as experienced by legacy TOU customers, in compliance with the principles of D.17-01-006.[190] For those customers on rate schedules with high concentrations of legacy TOU customers – A-6, E-19R, E-20R – the levelization takes place over several years to allow for a transition to new peak period and peak to off-peak price ratios.[191]

Notably, the TOU settlements do not include rates for residential customers. PG&E states that a TOU transition plan for residential customers was included in the residential rate design settlement approved in D.15-11-013, and implies that the settlement from that decision satisfies the requirements of D.17-01-006.[192]

Our standard for reviewing contested settlements appears above in Section 2. We must review the TOU settlements to determine if they are reasonable in light of the whole record, consistent with law, and in the public interest. We reviewed the TOU settlements' terms, and the ALJs assigned to this proceeding examined witnesses testifying on behalf of the settling parties on

---

[189] D.17-01-006 at 6.

[190] D.17-01-006 at 64, fn 48.

[191] D.17-01-006 at 8.

[192] Motion to Adopt TOU Settlement at 4.

March 1, 2018, and April 10, 2018. We find that the TOU settlements should be approved for reasons including the following:

- The TOU settlements' treatment of legacy solar customers complies with the mandates and guidelines of D.17-01-006 and other applicable law.
- A gradual lowering of the generation differential between the peak and part-peak periods over several years for A-6, E-19R, and E-20R customers is appropriate given the high concentration of legacy TOU customers on those rates.
- The TOU settlements represent an effort by many parties to this proceeding, including consumer and renewable energy development advocates, to craft a transition in TOU peak periods and rates that allows for customers with renewable energy systems to recoup a reasonable amount of their investment.

For reasons including those listed above, we find that the TOU settlements are reasonable in light of the whole record, consistent with law, and in the public interest. We direct PG&E to implement the terms of the TOU settlements as soon as practicable following the issuance of a final Commission decision in this proceeding.

The only caveat to our approval of the TOU settlement is that we modify how the TOU settlement applies to RES-BCT customers. Because this element of the TOU settlement was subject to litigation, we do not consider this modification of the TOU settlement's rate design as it applies to RES-BCT customers to be a rejection of the settlement.[193] As a matter of law the TOU

---

[193] PG&E appears to concur with this assessment that the TOU settlement may be applied differently to RES-BCT customers while not rejecting the TOU settlement per se (PG&E's March 23, 2018 Additional Exhibits per ALJ Ruling at 10).

settlement is approved, but shall be applied to RES-BCT customers as described subsequently in this decision.

6.9. Streetlight Rates

On January 4, 2018, PG&E served a motion for adoption of a supplemental settlement on streetlight rate design issues. The settling parties are PG&E and CAL-SLA. PG&E's streetlight rates include schedules LS-1, LS-2, LS-3, OL-1, and CCSF.

The settlement appears to be uncontested, and the City and County of San Francisco did not protest or serve opposing testimony to PG&E's original streetlight proposal. We presume that the settlement is uncontested.

Our standard for reviewing uncontested settlements appears above in Section 2. We must review the settlement to determine if it is reasonable in light of the whole record, consistent with law, and in the public interest. We reviewed the settlement's terms and we find that the settlement should be approved as the proposed facility charges, customer charges, and energy charges are very similar to the current streetlight charges.[194] The proposed changes to the streetlight charges are therefore reasonable.

We also believe that the continuation of the Network Controlled Dimmable Streetlight Pilot Program is warranted and reasonable. However, while the settlement sets out workshops that PG&E may use to craft a request for funding and rate designs for a fully automated dimmable streetlight billing

---

[194] A table comparing current and proposed streetlight rates can be found in section 1-1 of PG&E's March 23, 2018 Additional Exhibits per ALJ Ruling, served on March 23, 2018. The proposed LS-3 customer charge does increase by 25%, but we have found such increases in customer charges to be reasonable in the past, and nothing in the record of this proceeding suggests that it is an unreasonable change.

system at its own discretion,[195] we order PG&E to propose such a system and a rate design to give effect to it. We agree with CAL-SLA that a fully automated dimmable streetlight system for streetlight customers is in the public interest and should be pursued expeditiously.[196] We encourage CAL-SLA to pursue this issue and work with PG&E to create a fully automated dimmable streetlight system that can be approved by the Commission as soon as possible. PG&E must make a proposal for such a system and a rate design to give effect to it in its next GRC Phase II application.

We otherwise direct PG&E to implement the streetlight rate design settlement as soon as practicable following the issuance of a final Commission decision in this proceeding.

6.10. Petition to Modify D.18-01-013 Regarding Direct Access and Community Choice Aggregation Fee Rate Design Issues

Previously in this proceeding, D.18-01-013 adopted a settlement on Direct Access and Community Choice Aggregation Fee Rate Design Issues (DA/CCA settlement). The DA/CCA settlement was executed by the Direct Access Coalition, EUF, MCE, Sonoma Clean Power, and PG&E on October 9, 2017.

Subsequent to the issuance of D.18-01-013, and in compliance with that decision, PG&E filed advice letter 5225-E to implement certain revisions to its Electric Rule 22 and Electric Rule 23 as approved by D.18-01-013. This advice letter was approved by Energy Division in March, 2018.

---

195 Streetlight Rate Design Settlement at 7-8.

196 CALSLA-1 at 16-19.

Subsequently, the parties to the DA/CCA settlement identified the possibility that some of the language in the DA/CCA settlement could be misinterpreted. The settling parties agreed to revisions to the settlement in order to clarify these potential misinterpretations. PG&E filed a petition to modify D.18-01-013 on April 25, 2018, in order to give effect to the revisions to the settlement.

In its petition to modify D.18-01-013, PG&E states that the settling parties believe that the proposed revisions to the DA/CCA settlement, revising Electric Rules 22 and 23, would reduce the potential for misinterpretation and misunderstanding about the DA and CCA providers' obligations if they select the "Rate Ready Billing Option" whereby PG&E places certain DA and CCA charges in the bill that PG&E sends the customer.

As the petition to modify demonstrates that all of the original parties to the DA/CCA settlement agree to the modifications proposed by the petition, the petition is approved. PG&E is ordered to file an advice letter making the proposed changes to Electric Rules 22 and 23 no later than 30 days after the issuance of this decision.

7. Issues Litigated by the Parties

Certain issues related to PG&E's proposed rate designs were litigated by the parties and were not settled. These litigated issues generally address the question of whether PG&E's proposed rate designs are reasonable and are therefore within the scope of this proceeding. We address each of these litigated issues below.

7.1. Transition of E-37 Customers

PG&E's E-37 rate was formerly available to those medium and large commercial customers that primarily used electricity for the purpose of oil and gas extraction. It was first adopted in PG&E's 1997 RDW application in D.97-09-047 and implemented in 1998 as an incentive to promote the expansion of domestic oil production and return idle oil wells to production.[197] In D.11-12-053, the Commission closed the rate to new customers, and in D.15-08-005 the Commission adopted an uncontested settlement that completely eliminated E-37 beginning in November 2017.[198]

In its opening testimony served in 2016, PG&E confirmed that "E-37 may include customers over 500 or 1,000 kW, but will be eliminated beginning November 1, 2017"[199] in accordance with D.15-08-005 which held that "Schedule E-37 shall be terminated for customers with 12 months of interval data beginning on November 1, 2017. Beginning November 1, 2017, or with each successive November 1, Schedule E-37 customers shall be transferred to their otherwise applicable commercial or industrial rate schedule."[200] PG&E noted that almost 90% of E-37 customers were transitioned to otherwise applicable rates by November 2017.[201]

On March 17, 2017, CIPA served direct testimony regarding the pending transition of E-37 customers to different rates. CIPA requested that the Commission mitigate the expected bill impacts of the pending transition of E-37 customers by approving a discount of 11.5% on their new tariff rates under either E-19 or E-20, whichever would be applicable to the former E-37 customer. CIPA

[197] PG&E-16, Chapter 4 at 8.

[198] PG&E-16, Chapter 4 at 8.

[199] PG&E-8, Chapter 6 at 5.

[200] D.15-08-005 at 23.

[201] PG&E-16, Chapter 4 at 9.

also requested that the Commission order PG&E to conduct a "true cost of service study" of all potential oil and gas-producing customers for presentation in its next GRC Phase II, and consider establishing a special rate for those customers based on the results of that study.[202]

In its supplemental testimony of January 25, 2018, CIPA withdrew its proposal for an across-the-board 11.5% rate discount, and instead sought a "rate limiter" that would limit the annual economic impact of rate increases for former E-37 customers.[203] CIPA continued to maintain its previous requests for a cost of service study and exploration of an alternative rate for oil and gas producers.

CIPA's proposal for a rate limiter would be set at 5% starting in 2018 and would be effective until the rates created in the next PG&E GRC Phase II become effective. Alternatively, CIPA proposed a rate limiter of 3%, 7%, and 12% in years 1, 2, and 3 presumably beginning in 2018.[204]

CIPA's rationale for its proposal is that the bill impacts generally faced by former E-37 customers would be large, and that it would result in an unjust cost shift (or benefit) to those non-former-E-37 customers that take service on E-19 or E-20. The rate limiter proposed by CIPA is meant to "cushion the rate shock impact" for former E-37 customers.[205] CIPA argues that its proposed rate limiter would, in any event, represent a de minimus amount of revenue when compared to the total revenue requirement of the E-19 and E-20 classes.[206]

---

[202] CIPA-2 at 1-2.

[203] CIPA-2 at 4-5.

[204] CIPA-2 at 5.

[205] CIPA-2 at 6.

[206] CIPA Opening Brief at 8.

While the E-37 rate was terminated in a previous Commission decision through its approval of a settlement on agricultural rate design issues, CIPA argues that the approval by the Commission of a settlement to terminate a rate schedule does not per se deny the customers on the terminated rate schedule protections from bill impacts.[207]

In its opening brief, CIPA summarizes its previous recommendations and requests the following modifications to the MLLP settlement to give effect to its recommendations: 1) requiring PG&E to perform a cost of service study for oil and gas producers in its territory to be included in its next GRC application, 2) authorizing parties to propose a cost-based rate for oil and gas producers based on that study, and 3) approve a rate limiter of 5% for former E-37 customers now taking service under the E-19 or E-20 tariff, that would expire once the rates proposed in the 2020 GRC application became effective.[208]

In its rebuttal testimony, PG&E contends that a cost of service study is not required due to the fact that PG&E previously submitted a cost of service study on E-37 customers in its 2014 GRC Phase II proceeding. PG&E states that its previous study shows that the average cost of service for transmission and primary-voltage E-37 customers was similar to that of E-19 and E-20 customers, with higher costs to serve E-37 secondary voltage customers, and that these findings justify a migration of E-37 customers to their otherwise applicable schedules. At a basic level, PG&E argues that the issues raised by CIPA were

---

[207] CIPA-2 at 9.

[208] CIPA Opening Brief at 3.

already litigated and resolved by interested parties in each of PG&E's 2011 and 2014 GRC Phase II proceedings.[209]

PG&E maintains that because the transition of former E-37 customers to otherwise applicable rates such as E-19 and E-20 has already occurred, any rate limiter now applied to them would constitute prohibited retroactive ratemaking if applied to bills incurred after November 2017, to the present. PG&E also asserts that the bill impacts for former E-37 customers are generally moderate or mild, and on average were approximately 8%. PG&E argues that this level of average bill impact does not warrant intervention by the Commission in the form of a rate limiter.[210] PG&E also notes that they defaulted former E-37 customers onto the "best rate" for that customer, even if it was not E-19 or E-20, in order to mitigate bill impacts as much as possible.[211]

PG&E's testimony also reflects on previous bill impact analyses of E-37 customers provided to the Commission in PG&E's direct testimony in its 2014 GRC Phase II proceeding.[212] The record reflected, at the time the decision was made to terminate the E-37 schedule, that a transition of E-37 customers to otherwise applicable rates would result in bill increases for those customers on average of around 8%.[213]

In light of the testimony received on this issue, and the evidence gathered during hearings on February 13, 2018, we do not grant CIPA's proposals for a

---

209 PG&E-16, Chapter 4 at 9.

210 PG&E-16, Chapter 4 at 10, 12.

211 PG&E-16, Chapter 4 at 12-13.

212 Transcript at 399-400.

213 PG&E-16, Chapter 4 at 14-15.

rate limiter for former E-37 customers, or a new cost of service study for oil and gas producing customers. The record is clear that the Commission approved the termination of the E-37 schedule and the transition of E-37 customers to otherwise applicable tariffs in November 2017, and that the record in the 2014 PG&E GRC Phase II proceeding reflected that adverse bill impacts would result for those customers on an average basis. It is also apparent that PG&E is attempting to minimize the bill impact on former E-37 customers by defaulting them to their "best rate," even if that rate is an optional rate that customers are not usually defaulted to. Given that, the existence of adverse bill impacts for former E-37 customers is not sufficient cause to adopt CIPA's proposed rate limiter at this time.[214]

A new cost of service study for these customers is also not warranted. PG&E's previous study of E-37 customers indicated that they had costs of service that were similar to other customers on comparable rates, and we do not believe CIPA has provided enough new evidence to warrant the commission of a new cost of service study at this time.

In short, the holding of D.15-08-005 remains. E-37 customers shall continue their transition to their otherwise applicable rate without any bill mitigation, as previously ordered.

---

[214] CIPA is correct when asserting that our approval of a previous settlement in PG&E's 2014 GRC Phase II does not prohibit their request for a rate mitigation measure in this proceeding (CIPA Reply Brief at 7). We decline to find that the request is justified in light of the record developed in this proceeding.

7.2. Special Rates for A-10, E-19, and E-20 Customers that Install Energy Storage Devices

While they are parties to the MLLP settlement generally, both SEIA and CALSSA propose separate, optional rates that would be available to MLLP customers that install energy storage devices. In general, SEIA proposes that these customers be eligible for a rate that is similar to the "Option R" rates currently offered to solar customers, but with residual distribution non-coincident demand charges converted to daily peak demand charges. CALSSA proposes a different rate design that maintains TOU-based demand charges but shifts a substantial amount of revenue recovery from non-coincident demand charges to peak period demand charges.

Ostensibly, these energy storage rates would be designed to encourage the charging of energy storage systems during hours when the GHG-intensity of the grid is relatively low (i.e., PG&E's proposed off-peak periods), and discharge during hours when the GHG-intensity of the grid is relatively high (i.e., PG&E's proposed peak periods).[215] They also intend for these rates to provide greater incentives for the installation of customer-sited energy storage, beyond SGIP incentives, in accordance with general Commission policy to increase energy storage adoption.[216]

PG&E generally disagrees with these proposals and believes they are premature. In particular, PG&E argues the GHG emissions related to storage

---

[215] SEIA Opening Brief at 2; CALSSA Opening Brief at 8.

[216] CALSSA Opening Brief at 2; SEIA Opening Brief at 2. CALSSA also makes an argument in passing that their storage rate proposal may help existing solar customers transition to the proposed revised TOU periods (CALSSA Opening Brief at 2).

operation is currently being addressed in a different proceeding – R.12-11-005. That proceeding convened a working group that is tasked with addressing incentives and operational requirements likely to improve the GHG impact of SGIP-eligible energy storage systems, and was ordered to report out on proposals by June 15, 2018. PG&E notes that rate design changes, such as those proposed by SEIA and CALSSA in this proceeding, are not explicitly within the scope of the working group's activities. PG&E also notes that while they have agreed to specific rates for energy storage customers in other settlements, they declined to do so in the MLLP settlement out of a concern for cost shifts and cross-subsidies that may result from such rates. PG&E also raises a general concern that significant reductions in non-coincident distribution demand charges for energy storage customers would create incentives that could potentially lead to overloaded circuits where such circuits are dominated by larger MLLP customers with (presumably) large energy storage systems.[217]

PG&E does grant that it would be appropriate to consider energy storage-specific rates for MLLP customers in a future rate design proceeding, such as the scheduled 2019 RDW proceeding.[218]

CLECA joins PG&E in opposition to the proposals of SEIA and CALSSA. In general, CLECA alleges that the proposed storage rates have no basis in cost-based ratemaking principles, and are not required to stimulate the energy storage market.[219]

---

[217] PG&E Opening Brief at 35.

[218] PG&E Opening Brief at 31.

[219] CLECA Reply Brief at 12-13.

7.2.1. CALSSA's Proposed Storage Rate

We first turn to CALSSA's proposal to create an energy storage-specific rate for MLLP customers that would assign 50% of the distribution revenue to be collected through non-coincident demand charges to peak demand charges.[220] CALSSA's main justification for its proposal is that the MLLP settlement's standard rates for MLLP customers have higher non-coincident demand charges than peak demand charges.[221] Without moving some of the revenue collected by non-coincident demand charges to peak demand charges, CALSSA reasons that storage dispatch algorithms would likely target demand reduction at the customer's non-coincident peak rather than the system peak of 4 p.m. to 9 p.m. CALSSA argues that adopting its proposed storage rate would mean customers would be expected to reduce demand during TOU peak hours rather than whatever hours happen to correspond with the customer's non-coincident peak demand.[222] This would, in turn, lead to greater reductions in GHG emissions and greater reductions in system peak demand.

PG&E's arguments opposing CALSSA's proposal center on three main themes: 1) the recovery of "non-coincident costs" through peak demand charges is inappropriate from a rate design perspective;[223] 2) the SGIP GHG working group is tasked with developing a remedy to the problem CALSSA seeks to address with their proposed rate – namely the GHG impacts of energy storage

---

[220] *See* CALSSA-6 for illustrative MLLP rates based on its storage rate proposal.

[221] CALSSA Opening Brief at 5.

[222] CALSSA Opening Brief at 6.

[223] PG&E Opening Brief at 32.

operation; and 3) the cross-subsidies that may result from CALSSA's proposed rates are unknown and could be significant.[224]

We addressed the issue identified by CALSSA generally in our rejection of the MLLP settlement's design of distribution demand charges. As noted previously in this decision, we find that PG&E's definition of "non-coincident costs" is flawed, and that a certain proportion of these marginal costs should be collected through peak and part-peak demand charges for MLLP customers, regardless of whether they install energy storage. Therefore, the basis for comparison used by CALSSA to justify its proposed rate – the MLLP settlement rates – is no longer relevant. In fact, the MLLP rate designs we propose in this decision should create peak demand charges (when including distribution and generation charges) that are larger than the non-coincident demand charges on each MLLP rate schedule, which will make the rate design incentive problem identified by CALSSA moot.

In the following table, we compare the MLLP settlement's distribution demand charges, CALSSA's illustrative distribution demand charges for its storage rates, and our illustrative MLLP distribution demand charges that result from the MLLP rate design methodology proposed by this decision. While our demand charge rate design does not result in peak demand charges as high as that sought by CALSSA, we propose to move the MLLP settlement rates substantially in that direction.

---

[224] PG&E Opening Brief at 29-33.

Rate Schedule and Summer Distribution Charge	MLLP settlement	Commission proposal	CALSSA proposal[225]
E-19-S Peak Distribution Demand Charge	$5.91/kW	$9.14/kW	$12.43/kW
E-19-S Non-Coincident Distribution Demand Charge	$12.25/kW	$10.54/kW	$6.13/kW
E-19-P Peak Distribution Demand Charge	$5.51/kW	$8.51/kW	$10.32/kW
E-19-P Non-Coincident Distribution Demand Charge	$8.82/kW	$7.30/kW	$4.41/kW
E-20-S Peak Distribution Demand Charge	$4.97/kW	$9.02/kW	$11.14/kW
E-20-S Non-Coincident Distribution Demand Charge	$11.72/kW	$9.80/kW	$5.86/kW
E-20-P Peak Distribution Demand Charge	$4.89/kW	$8.54/kW	$10.20/kW
E-20-P Non-Coincident Distribution Demand Charge	$9.86/kW	$8.08/kW	$4.93/kW

[225] As described in CALSSA-6.

For these reasons, the proposal of CALSSA for a separate rate design for MLLP energy storage customers is rejected.

7.2.2. SEIA's Option S Rate

SEIA's proposal for an energy storage-specific MLLP rate – called an "Option S" rate – is distinct from CALSSA's proposal. SEIA's Option S rate would be available to customers on those rate schedules who install on-site SGIP-eligible storage with a discharge capacity that is at least 10% of the customer's peak demand over the previous 12 months. The Option S rates would be identical to PG&E's current Option R rates, with the exception of a daily coincident peak demand charge that would recover all distribution costs currently recovered by the non-coincident demand charges for Option R customers.[226]

SEIA argues that this kind of rate design will incent energy storage usage that provides maximum benefit to the entire grid. SEIA argues that their daily coincident peak demand charge would create incentives for the energy storage system to discharge during times that would help reduce grid demand and thereby reduce GHG emissions.[227] SEIA also argues that energy storage-specific rates will assist the Commission's overall goal of creating incentives for energy storage installations.

SEIA maintains that the 2016 SGIP Energy Storage Impact Evaluation (2016 SGIP Report)[228] demonstrates that rate designs that align customer

---

226 SEIA Opening Brief at 2-3.

227 SEIA Opening Brief at 3.

228 The first section of the 2016 SGIP Report was received into evidence as SEIA-3.

incentives with hours of high marginal GHG emissions are essential to ensuring that customer-sited energy storage systems provide GHG benefits.[229] This report specifically notes the impact of demand charges on energy storage dispatch, and the need for demand charges to be highly correlated to peak periods in order to drive energy storage behavior that maximizes reductions in GHGs.

SEIA also proactively argues against the idea that the SGIP GHG working group should be relied on to address this issue, as the charter of the working group does not include the ability to make recommendations on rate design issues.[230] SEIA also disputes PG&E's argument that overloaded feeders or circuits may result from reduced non-coincident distribution demand charges, and that PG&E's support for optional energy storage rates in the residential rate design and small commercial rate design settlements is inconsistent with PG&E's opposition to SEIA's Option S rate proposal.[231]

PG&E's arguments opposing SEIA's proposal are similar to their arguments opposing CALSSA's proposed energy storage rates and center on three main themes: 1) the recovery of "non-coincident costs" through peak demand charges is inappropriate from a rate design perspective;[232] 2) the SGIP GHG working group is tasked with developing a remedy to the problem SEIA seeks to address with the Option S rate – namely the GHG impacts of energy

---

[229] SEIA Opening Brief at 5.

[230] SEIA Opening Brief at 6. *See also* CALSSA Opening Brief at 3 ("The working group will not make recommendations on rate design and is not modeling the impacts of the rates for large commercial storage customers that have been proposed in the instant proceeding").

[231] SEIA Opening Brief at 7-9.

[232] PG&E Opening Brief at 32.

storage operation; and 3) the cross-subsidies that may result from SEIA's proposed rate are unknown and could be significant.[233]

With respect to the distinguishing element of SEIA's proposal for a daily demand charge, PG&E argues that such charges are unworkable and provided a diluted price signal to incent GHG reductions, rather than a strong signal to do so.[234]

We are persuaded by SEIA's arguments that the Option S rate will assist customer-sited energy storage systems to produce ratepayer benefits by avoiding marginal utility costs and reducing GHG emissions. We also find that the Option S rate is generally consistent with PG&E's efforts in the residential rate design and small commercial rate design settlements to create limited, opt-in rates for energy storage customers that will lead those customers to avoid utility costs and reduce their GHG emissions. SEIA's proposal for an Option S rate is therefore approved, as modified below, for A-10, E-19, and E-20 customers.

We limit the capacity that may be enrolled in the Option S rate in order to address the concern raised by PG&E surrounding the unknown cost shift that may result from customer participation on this rate. Participation in Option S shall be limited to 324 MW[235] of installed energy storage rated capacity, with 108 MW portions of this total assigned to each of the A-10, E-19, and E-20 customer groups. In other words, once enough A-10 customers enroll to have

---

[233] PG&E Opening Brief at 29-33.

[234] PG&E Opening Brief at 34.

[235] We choose this figure based on an analysis by Energy Division of the likely MW of customer-sited energy storage to be installed in PG&E territory over the next few years in response to SGIP incentives.

enrolled 108 MW of energy storage capacity, then Option S will no longer be available for A-10 customers.

The adopted Option S rate shall have the following characteristics, as modified from the original SEIA proposal:

- We do not require SGIP-eligibility of an energy storage system in order to participate in Option S as requested by SEIA. We are concerned that doing so would mean that the rate would become tied to SGIP and its administration, when the program itself is due to sunset in 2020. This calls into question how PG&E would administer the Option S rate after 2020 if Option S eligibility was tied to SGIP and its rules. PG&E must use the same eligibility language as it uses for the A-1 STORE rate.
- The energy storage system must have a rated capacity in watts which is at least 10% of the customer's peak demand over the previous 12 months.[236] The Option S tariff sheet shall include a method for calculating rated capacity that mirrors the existing calculation from the SGIP Handbook.
- PG&E shall begin the design of the Option S rate by making it identical to the Option R rate available to the customer. For A-10 customers that do not have an Option R rate available, PG&E must construct an Option R rate for those customers[237] that mirrors the rules for Option R customers on E-19 and E-20, with the addition of daily distribution demand charges as described below.
- After duplicating the Option R rate design, 80% of the revenue that would otherwise be collected from Option R A-10, E-19, or

[236] For customers with less than 12 months data, the methodology currently described in the SGIP Handbook for determining the peak load of customers with less than 12 months of data shall be used by the Option S tariff.

[237] To be clear, we are not ordering PG&E to create an Option R rate that would be available for A-10 customers to opt into. The creation of an A-10 Option R rate is only for the purpose of designing an A-10 Option S rate.

E-20 customers by non-coincident distribution demand charges (referred to by PG&E as "maximum" demand charges) shall be collected instead through daily demand charges assessed during the peak period only (4 p.m. to 9 p.m. for MLLP customers) for customers on Option S.

- After duplicating the Option R rate design, 20% of the revenue that would otherwise be collected from an Option R A-10, E-19, or E-20 customers by non-coincident distribution demand charges (referred to by PG&E as "maximum" demand charges) shall be collected through a non-coincident distribution demand charge for customers on Option S, except that no distribution demand charges may be assessed between 9 a.m. and 2 p.m. each day. An analysis of the data in CALSSA-2 indicates that the time period of 9 a.m. to 2 p.m. each day is when the marginal GHG emissions of the grid are generally at their lowest, and therefore this time period is appropriate for the "demand charge holiday" implicitly proposed by SEIA's proposal. This also corresponds to the "super off-peak" period adopted by PG&E and the MLLP settling parties for the months of March, April, and May, although under Option S this period of time free of demand charges will last all year.
- For the sake of clarity, and to align with the intent of SEIA's proposal, Option S shall collect all distribution demand charge revenue through daily demand charges for participating A-10, E-19, and E-20 customers. In other words, all existing Option R monthly peak demand charges shall be converted to daily peak distribution demand charges for Option S customers. And all existing Option R monthly part-peak demand charges shall be converted to daily part-peak distribution demand charges for Option S customers.
- The daily demand charge price shall not vary throughout a given month (i.e., it must be a constant $/kW/day during the month).

We adopt this proposal for the following reasons:

- As discussed previously in this decision in Section 6.6.2, and as demonstrated in SEIA's testimony and reply brief, PG&E's definition of "non-coincident" distribution costs to be collected through non-coincident distribution demand charges for MLLP customers is flawed.

- The creation of a daily peak distribution demand charge, working alongside the other features of the Option S rate, will likely create incentives for energy storage that maximize the system benefits that can be provided by such technology by creating a daily incentive to reduce customer demand during peak hours (i.e., the rate will maximize discharge of the energy storage system during peak system hours every day of the month).[238] As explained by SEIA, the disadvantage of existing monthly demand charges is that they create little incentive to conserve demand once high customer demand is registered once in a 30 day period. Daily demand charges address this shortcoming.

- We previously encouraged PG&E to propose daily demand charges for its solar customers and its customers that otherwise had erratic loads, and this proposal helps to fulfill that ambition.[239]

- SEIA is correct that collecting all marginal distribution costs through energy and demand charges that apply during the peak period will be a departure from cost causation, as not all marginal distribution costs are peak-related.[240] But this departure is justified by the likely creation of incentives for energy storage to maximize the system benefits that can be provided by such technology.

---

238 SEIA-1 at 48-49, 52-53; SEIA Reply Brief at 4-6.

239 D.14-12-080 at 19-20 ("…in a future rate design proceeding, PG&E may propose the use of peak and part-peak average demand charges or daily peak demand charges that better align solar and other erratic load customers' demand charges with their average expected contributions to coincident peak demands. By lessening the bill impact of demand during the single highest interval of each billing cycle, such an approach would provide similar bill 'smoothing' benefits as recovering coincident demand related costs in peak period energy rates while maintaining energy rates closer to wholesale marginal costs").

240 SEIA Reply Brief at 4.

- The SGIP GHG working group is not chartered to consider changes to rate design, and therefore cannot be relied upon to address this issue with as much efficacy as Option S.
- PG&E's assertion that daily demand charges exclusively collected during peak periods will, by design, lead to sub-optimal energy storage charging during peak periods and threaten grid integrity during off-peak periods[241] is speculative and not supported by the record of the proceeding.
- PG&E's concern regarding the potential cost shift that may result from the Option S rate is noted, and we impose a participation cap of 324 MW in order to address that concern.
- Adoption of this proposal will help PG&E meet the principle of D.17-01-006 that a menu of rate design options should be offered for different kinds of customers, including those that install energy storage technology.[242]

PG&E must make available the Option S rates at the earlier of 1) the same time that all other A-10, E-19, and E-20 rates as modified by the MLLP settlement are available for opt-in enrollment, or 2) January 1, 2020.

As noted above, our primary rationale for adopting the Option S rate is that we find it is likely to create incentives for customer-sited energy storage to maximize its benefits to the electrical system and reduce GHG emissions that result from energy storage operation. Because daily demand charges have yet to be tested at this scale in California, it is important that we study the experience

[241] PG&E Reply Brief at 14-15. PG&E's assertion that it "does not always know when or how a large business customer may change its operations" cuts both ways. It means that PG&E must always be vigilant regarding the physical integrity of its grid, regardless of the rate structure, as an individual customer's response is never certain.

[242] D.17-01-006 at 8.

with Option S rates to determine if they optimize the behavior of customer-sited energy storage systems.

Therefore, PG&E is ordered to study the performance of a representative sample of Option S energy storage systems after 12 months of operation, and compare them with the performance of a representative sample of non-Option S energy storage systems of comparable size on the relevant MLLP rate (A-10, E-19, or E-20), to determine the impact of Option S rates on energy storage performance and any potential cost-shift that results from that performance. The cost-shift analysis must account for the benefit of reduced peak usage and reduced GHG emissions as well as avoided payments for embedded costs. This study is due at the time of PG&E's first rate design application filed after January 1, 2021.

7.3. The Master Meter Discount for ET and ES Customers

PG&E provides service to certain "master meter" customers that resell the electricity to their tenants. Master meter customers maintain sub-metering infrastructure to distribute the electricity to their tenants. In essence, master meter customers own and operate their own electricity distribution networks.

PG&E divides its master meter customers between two rate schedules: ET and ES. The ET rate is available to those master meter customers that operate mobile home parks. The ES rate is available to those master meter customers that operate other forms of multi-family housing. All of these rates have been closed to new customers since January 1, 1997.

The law recognizes that master meter customers that provide electricity distribution services to their tenants should be compensated for doing so. Public Utilities Code Section 739.5(a) states that "[t]he commission shall require the [utility] furnishing service to the master-meter customer to establish uniform rates for master-meter service at a level that will provide a sufficient differential to cover the reasonable average costs to master-meter customers of providing submeter service, except that those costs shall not exceed the average cost that the [utility] would have incurred in providing comparable services to the users of the service."[243]

The composition of the so-called master meter discount – the "differential" referred to in the law – is the subject of litigation in this proceeding. PG&E and WMA (a group representing Schedule ET customers in PG&E's territory) dispute the methodology and the value of the master meter discount that should be applied to master meter customers.

In order to calculate the discount in compliance with Public Utilities Code Section 739.5(a), we must estimate 1) the avoided costs that PG&E would have incurred in providing submeter service; 2) the line losses that compensate a master meter customer for the electricity that is ordinarily lost when it is transmitted across the master meter customer's distribution network; and 3) the diversity benefit adjustment (DBA) which reduces the master meter discount paid to the owner of a mobile home park to account for the fact that while the master meter operator receives a full baseline allowance for each tenant space, some tenants use less than the baseline allowance and some tenant spaces may be vacant. This methodology for calculating the master meter discount was used

[243] Public Utilities Code Section 739.5(a).

in the last Commission decision to consider these issues in depth – D.11-12-053 – and we adopt it in this decision as well.[244]

In its application, PG&E proposes to calculate the master meter discount consistent with the methodology we adopted in D.11-12-053. That decision allowed PG&E to 1) include replacement costs through application of the Real Economic Carrying Cost (RECC) to new equipment connection costs, 2) to exclude any EPMC factors, 3) to consider new connection costs to properly be the costs as capped by PG&E's line extension allowances under Rules 15 and 16 with application of the "rental method," and 4) use PG&E's multi-family residential costs as a reasonable proxy for the average avoided costs to otherwise directly serve tenants in master meter mobile home parks (MHPs). For the DBA, PG&E proposes to use the same database and analytical methods used in its prior two GRC Phase II proceedings. The main difference in this proceeding is that the DBA analysis now accounts for the minimum bill that very low-usage residential customers are charged.

In general, PG&E proposed to calculate the ES discount by basing it on the value of the ET master meter discount, in accordance with previous Commission decisions.[245] PG&E claims that the Schedule ES discount calculation methodology is unopposed. While that is strictly true, WMA opposes the ET calculation methodology, which forms the basis for PG&E's ES discount calculation. Nevertheless, it is true that the ES discount calculation methodology

---

[244] D.11-12-053 at 37-40.

[245] PG&E-16, Chapter 3B at 8-10.

itself is unopposed in this proceeding, and we agree with PG&E that it should be adopted.

PG&E initially proposed significant reductions to the master meter discount for both ET and ES customers. For ET customers, PG&E proposed a reduction from $5.48/month/tenant space in effect in 2016 to $1.18/month/tenant space. For ES customers, PG&E proposed a reduction from $1.54/month/tenant space in effect in 2016 to $0.76/month/tenant space. PG&E does not fully describe the reasons for such a significant decrease, but they did identify that the DBA increased modestly for master meter customers.[246] WMA's testimony makes clear that the reduction in the basic discount (i.e., the master meter discount before the DBA and line loss adjustments are applied) from $8.58/month/tenant space to $4.73/month/tenant space drove the overall reduction in the proposed master meter discount.[247]

WMA responded to PG&E's proposals in its opening testimony of March 15, 2017. As a general principle, WMA argued that the law creates no requirement that the master meter discount be crafted to equal the lowest feasible cost for the utility. Instead, WMA stated that the Legislature intended to establish a master meter discount that would maintain the viability of master metered distribution systems and the equity of treatment between ET customers and other customers.[248] WMA alleged that changes to the master meter discount since 1987 now mean that it no longer adequately funds actual costs to own and operate a distribution network, meaning that the master meter customers operate

[246] PG&E-8, Chapter 4 at 30-32.

[247] WMA-1 at 3.

[248] WMA-1 at 2.

these networks at a loss.[249] The thrust of WMA's argument is that the methodology used by PG&E, and adopted by D.11-12-053, should be rejected in this proceeding as it does not credit master meter MHP owners sufficiently for the costs incurred in operating their submetering systems.

In order to address the alleged failing of PG&E's methodology, WMA argues that the master meter discount should be frozen rather than significantly cut as proposed by PG&E. Alternatively, WMA offered three methodologies distinct from that offered by PG&E's application for calculating the master meter discount: 1) a method based on line extension allowance methodologies, 2) a method based on recalculations of PG&E's original dataset, and 3) a method based on revised measures of the revenue responsibility for multi-family service. Under any of these methods, the discount would increase on a $/month/tenant space basis compared to PG&E's current master meter discount.[250]

Before we discuss each of these proposals in turn, we state here our finding that PG&E's proposed methodology is consistent with the methodology for calculating the master meter discount as adopted in D.11-12-053. While WMA advances several arguments for why a different methodology should be used, and why PG&E's proposed methodology does not comply with the requirements of Public Utilities Code Section 739.5(a), we reject those arguments. We hold in this decision that PG&E's proposed methodology complies with D.11-12-053 and Public Utilities Code Section 739.5(a), and consequently base our calculation of the master meter discount on PG&E's proposed methodology

---

[249] WMA-1 at 6-9.

[250] WMA-1 at 4.

7.3.1. WMA's Proposal to Freeze the Master Meter Discount at its Current Level

In response to PG&E's proposal to substantially reduce the master meter discount, WMA first argues that the Commission should simply freeze the current master meter discount. WMA argues that this would be consistent with PG&E's proposal to freeze revenue allocation for customer classes generally.[251]

PG&E responded that the ET master meter discount is a rate schedule, and not a "revenue allocation" that should be frozen to accord with other revenue allocation determinations in this proceeding.[252] PG&E also notes that a freeze is impossible if PG&E's avoided costs to serve master meter customers decline, as that value sets the cap for the master meter discount, and therefore the master meter discount is reduced as PG&E's avoided costs decline.[253] Finally, PG&E argues that even if revenue allocations to other classes are kept constant in this proceeding, the revenues themselves are not and therefore the rates for all classes are subject to change. These changes to rates occur even if the revenue allocation itself is frozen.[254]

We decline to adopt WMA's proposal to freeze the master meter discount at its current level. D.11-12-053 established the methodology by which we should calculate the master meter discount, and we continue to use that methodology in this decision even if it leads to a master meter discount that is less than the current discount.

---

[251] WMA-1 at 3-4, 9.

[252] PG&E-16, Chapter 3B at 40.

[253] PG&E-16, Chapter 3B at 41.

[254] PG&E-16, Chapter 3B at 41.

7.3.2. WMA's Argument that SCE and SDG&E Submeter Discounts Show that PG&E's Discount is Too Low

In supplemental testimony, WMA raises the argument that SDG&E's submeter discount of $8.28/month/tenant space and SCE's proposed submeter discount of $6.73/month/tenant space demonstrate the unreasonableness of PG&E's proposal for an ET discount of $1.18/month/tenant space.[255] WMA further argues that the other two utilities have closer relationships between their line extension allowances and submeter discount than PG&E's proposed discount, further demonstrating the unreasonableness of PG&E's proposal.[256]

TURN argues that WMA's introduction of recently proposed and adopted submeter discounts for other utilities are irrelevant for the following reasons: 1) there is no basis for the claim that the Commission should apply a consistent inter-utility test to determine if PG&E's submeter discount is reasonable, 2) D.04-04-043 found that different utilities will have different submeter discounts as all utilities have different costs of service, and 3) all parties to the proceeding leading to D.04-04-043 opposed the idea of a single statewide discount. Additionally, PG&E points out that WMA's comparisons are not comparable to PG&E's proposal, as the proffered SCE and SDG&E submeter discount values do not include adjustments for the DBA.[257]

We agree with TURN that a statewide test of reasonableness for the submeter discount is not required, and we do not adopt one here. All utilities

[255] WMA-2 at 2.

[256] WMA-2 at 3-4.

[257] PG&E-16, Chapter 3B at 101.

will have different avoided costs to serve MHPs, and as those avoided costs form the cap on the submeter discount we expect that all utilities will have different submeter discounts. Further, we find that the comparisons to SDG&E's and SCE's submeter discounts are irrelevant, as the methodology to determine PG&E's ET discount adopted in D.11-12-053 does not include consideration of SDG&E's and SCE's submeter discounts. In other words, they are not appropriate inputs to determine PG&E's ET discount.

7.3.3. WMA's Argument that D.11-12-053's Conclusions Are Based on False Statements Made by PG&E

In supplemental testimony, WMA alleges that PG&E made false statements to the Commission in its 2011 GRC Phase II proceeding concerning the responsibility for trenching and substructure replacement costs when replacing utility systems in directly-metered MHPs. They argue that PG&E actually paid the costs to replace a gas distribution system at the Vineyard Valley MHP, contradicting their earlier assertions that such costs should be borne by the MHP owner. WMA argues that the Commission should therefore adjust the ET calculation methodology from D.11-12-053 to include the full costs for utility substructures and excavation "since PG&E pays the full cost for these cost elements."[258]

PG&E generally objected to WMA's accusation that it made false statements and argued that the gas system replacement costs at the Vineyard Valley MHP were borne by PG&E under the Aldyl-A Gas Pipe Replacement Program. This program apparently allowed PG&E to bear costs of replacement

[258] WMA-2 at 6.

that would ordinarily be the responsibility of the MHP owner under Gas Rule 16.[259]

We believe PG&E has adequately explained why it bore the costs of gas system replacement in the case of the Vineyard Valley MHP. We therefore decline to find that PG&E made false statements to the Commission in its 2011 GRC Phase II proceeding.

7.3.4. WMA's Argument that the Current Master Meter Discount Fails to Cover the Costs to Operate Submetering Systems

In general, WMA argues that its proposals in this proceeding, including the alternative methodologies described below, are justified by the fact that the current master meter discount fails to cover actual submetering costs as required by Public Utilities Code Section 739.5(a).[260] We address this foundational argument here for the sake of clarity.

WMA argues that the master meter discount has declined precipitously since 1987, and that other utility costs have risen since that time – showing that the reduction from 1987 levels is unjustified.[261] WMA further alleges that its survey of master meter MHP owners show that the average cost to run a submetering system is $7.25/month/tenant space, which is higher than the current master meter discount and many times higher than PG&E's proposed master meter discount.[262] WMA also alleges that the $10/month fee PG&E

---

[259] PG&E-16, Chapter 3B at 115.

[260] WMA-1 at 6-8.

[261] WMA-1 at 6-7.

[262] WMA-1 at 8.

charges to opt-out of the SmartMeter program shows that meter reading costs alone for residential customers are around $10/month, which is again higher than the current master meter discount.[263]

TURN argues that these alternative baselines should be rejected. TURN objects to using the 1987 ET discount as a baseline as it undercounts the discounts available from 1979-1987 to MHP owners and that it does not account for the large DBA "windfall" received by MHP owners from 1993 – 2012. TURN further argues that the methodology for calculating the master meter discount has changed since 1987, most notably in D.11-12-053, and therefore the 1987 ET discount is not an appropriate basis for comparison.

TURN also states that WMA's survey of MHP owners used to arrive at the $7.25/month/tenant space baseline is based on a survey that was not made available for review by any other party, and therefore cannot be tested to determine if it was rigorous enough to create a valid estimate of costs.[264]

We reject WMA's arguments that the master meter discount is too low compared to WMA's three alternate baselines. Comparing the 1987 master meter discount to the current master meter discount is inappropriate because, as TURN points out, the methodology for calculating the master meter discount has changed substantially in the intervening years. Using the 1987 master meter discount as a baseline for comparison to today's discount is therefore inappropriate and misleading. We also agree with TURN that WMA's purported survey of master meter MHP owner costs to operate submetering services is not

---

[263] WMA-1 at 8.

[264] TURN-4 at 6-7.

reliable. WMA did not make the source of the data available for review, nor did WMA explain its methodology or how it was a valid sample of the master meter MHP owners in PG&E's territory. The SmartMeter opt-out fees are also not an appropriate basis for comparison, as they seek to measure something completely distinct from the costs to operate a submetering system and apply to the residential class as a whole rather than master meter tenants.

Finally, even if we were to accept any of the three baselines proffered by WMA for comparison (which we do not), they would not prima facie lead us to invalidate the methodology adopted by D.11-12-053. The methodology adopted in that decision is designed to estimate the costs of master meter MHP owners to provide submetering service in a way that is capped by PG&E's costs to provide that service, in accordance with Public Utilities Code Section 739.5(a). WMA has not demonstrated how any of their proposed baselines show that the methodology per se is flawed, only that there are other potential ways of estimating the costs to provide submetering service.

7.3.5. WMA's Proposal to Use the Line Extension Allowance as a Basis for Calculating the Master Meter Discount

WMA's first alternate methodology essentially seeks to equate the line extension allowance value found in PG&E's Electric Rules 15 and 16 to the master meter discount. The line extension allowance refunds a certain amount of money to applicants that seek to extend PG&E's distribution network to their home or business. The current line extension allowance under Electric Rule 15 for a single residential unit is $2,154.[265] The line extension allowance is based on

[265] PG&E Electric Rule 15 at 5.

a calculation of the revenues that are expected to be collected from the customer requesting the extension.[266]

WMA reasons that because the value of line extension allowance equals the net present value of the revenue stream that PG&E would receive for owning the extension (and collecting revenue from the customer), that net present value is what the master meter customer deserves for operating the distribution network in lieu of PG&E's ownership and control.[267] WMA seeks to use the line extension allowance as an approximation of the costs that master meter customers incur to provide distribution services. WMA states that the line extension allowance's value is the expected revenue that PG&E would receive from a customer using the line extension, and that this "expected revenue equals the *average* cost of service, that is, total utility costs for transmission, distribution and generation allocated based on relative marginal costs…" (emphasis in original).[268]

WMA also makes several other arguments in favor of the principle that the line extension allowance should be used as the basis to calculate the master meter discount, including that the Legislature, through its passage of Assembly Bill (AB) 622 in 1996, intended for the principles used to calculate the line extension allowance be used to calculate the master meter discount,[269] and that the Commission in D.04-04043 and D.11-12-053 held that the master meter discount

---

[266] *See* PG&E Electric Rule 15 at 4 for the formula used to figure the line extension allowance.

[267] WMA-1 at 19.

[268] WMA-1 at 24. Using the total rate as a basis for calculating the master meter discount would be inappropriate due to the myriad costs that are covered by the total rate that have nothing to do with providing submetering services. *See* TURN-4 at 4.

[269] WMA-1 at 23.

is based on the principles established in an electric corporation's line and service extension rules.[270]

WMA then asserts that the average revenue generated by the customer applying for the line extension allowance should equate to the average costs to serve that customer, although WMA later grants that the allowance should equal net revenue *divided* by a "cost of service" factor.[271] WMA then makes a slightly different argument that the master meter discount should be the line extension allowance "calculated in reverse" to reveal annual costs to serve a customer.[272] However, their reverse calculation seeks the "net revenue" component of the line extension allowance rather than the underlying costs that comprise the cost of service factor. WMA then proceeds to estimate that the illustrative master meter discount should be $27.53/month/tenant space, based on the implicit assumption that the net revenues in the line extension allowance calculation equal the cost to PG&E to serve the customer seeking the line extension.[273]

TURN argues that WMA's proposed line extension allowance methodology should be rejected for three distinct reasons. First, they maintain that WMA's methodology implicitly includes EPMC-adjusted revenues, which a previous Commission decision held were inappropriate to use as a basis for the master meter discount.[274] Second, TURN asserts that WMA's methodology uses revenues based on requirements to serve the residential class as a whole, rather

---

270 WMA-1 at 24.

271 WMA-1 at 30.

272 WMA-1 at 32.

273 WMA-1 at 32-33.

274 TURN-4 at 8-9.

than costs to serve MHPs, and that such usage of class-wide residential costs to calculate the master meter discount was rejected by previous Commission decisions.[275] Third, TURN argues that the Legislature never intended for line extension allowances to be regarded as functionally equivalent to the master meter discount, and instead that the Legislature's intent in AB 622 was for the line extension allowance to be used as a subsidy that would help convert master meter systems to directly served systems to further "the positive public policy goals of converting parks to direct utility service and submetered tenants to first-class ratepayers."[276]

PG&E also offered several arguments countering WMA's proposal to base the master meter discount on the line extension allowance. First, PG&E argues that line extension allowances and master meter discounts are different tools to address different needs, with the allowance crediting a new customer certain costs for extending PG&E's lines and the master meter discount covering the costs to operate a distribution network, and therefore they are not "intrinsically linked."[277] PG&E also cited previous Commission decisions that rejected previous arguments made by WMA that the line extension allowance should be used as a basis for calculating the master meter discount.[278] PG&E also argued that WMA misquoted D.04-04-043, and that the decision does not stand for the proposition asserted by WMA. PG&E argues that while D.04-04-043 identified

---

275 TURN-4 at 9.

276 TURN-4 at 10-11.

277 PG&E-16, Chapter 3B at 44.

278 PG&E-16, Chapter 3B at 44-45, citing D.12-10-004 at 22-23, D.94-12-026, and D.12-08-046 (rejecting WMA's argument that the master meter discount methodology adopted by D.11-12-053 was discriminatory).

the costs that may be included in the calculation of the master meter discount, it says nothing about using the revenue-based line extension allowance calculation as an analogy for the cost-based master meter discount calculation.[279]

Like TURN, PG&E also refutes WMA's argument that the Legislature intended through AB 622 for the line extension allowance to be used to calculate the master meter discount. PG&E argues that the plain meaning of the statute as modified by AB 622 makes no reference to using the line extension allowance to calculate the master meter discount.[280] PG&E also mirrors TURN's argument that using the line extension allowance revenues as an input to calculate the master meter discount would use residential class-wide revenues to calculate the discount, which is in contravention of various Commission decisions holding that such class-wide inputs are improper to use in the master meter discount calculation.[281]

PG&E also objects to using revenue calculations based on the line extension allowance on the basis that the EPMC-scaled revenue present in those calculations includes far more costs than necessary to serve submetered customers. According to PG&E, those costs include payments to fund energy efficiency and demand response programs, as well as costs for preparing advice letter filings.[282] PG&E also points out that previous Commission decisions have

---

279 PG&E-16, Chapter 3B at 47. PG&E also argues at 48 that D.11-12-053 makes no such equivalence either, and rather refers to the inherent cap on the master meter discount set by PG&E's avoided costs.

280 PG&E-16, Chapter 3B at 46.

281 PG&E-16, Chapter 3B at 49-50, citing D.04-11-033 at 15-16, D.05-04-032, D.11-12-053, D.12-08-046, and D.12-10-004.

282 PG&E-16, Chapter 3B at 53.

rejected using EPMC-scaled revenue in the calculation of the master meter discount.[283]

WMA's recommendation to use the line extension allowance value to calculate the master meter discount is rejected for the following reasons.

We agree with TURN that the line extension allowance should not be viewed as a calculation of costs, and we have held as much in a previous decision.[284] It is the revenue provided by the line extension applicant that justifies the allowance, and the applicant's expected revenue is also used to figure the value of the allowance itself.[285] It is therefore not intended to be used to approximate the master meter customer's *costs* to serve submetered customers,[286] and we do not find that the Legislature intended for us to do so given the plain meaning of AB 622.[287]

We agree with TURN and PG&E that using the net revenue component of the line extension allowance credits the master meter discount with

---

[283] PG&E-16, Chapter 3B at 52 and 56.

[284] *See* D.07-07-019, Conclusion of Law 1; TURN-4 at 10 (noting that allowing MHP owners to use line extension allowances as a basis for converting their systems to PG&E ownership was meant to subsidize MHP owners to convert their systems).

[285] WMA-1 at 30 (granting that D.07-07-019 determined that the line extension allowance was based on the revenues expected to be collected from the customer receiving the extension).

[286] PG&E-16, Chapter 3B at 58 (noting that WMA has not provided evidence that the revenue-based calculations for the line extension allowance are consistent with a cost-based calculation of the master meter discount).

[287] As noted by WMA, there is no reference to the calculation of the master meter discount at all in the sections of the Public Utilities Code added by AB 622. It is impossible for us to divine the intent of the Legislature from the absence of language on a particular topic, as WMA would have us do. Furthermore, the Legislature has declined to adjust our previous decisions that cost-based methodologies specific to the costs faced by MHP owners should be used to calculate the master meter discount.

EPMC-adjusted rates, and that this inclusion of EPMC-adjusted revenues in the discount should be rejected as it does not reflect the costs of providing submetering service,[288] and contradicts previous Commission decisions rejecting the use of EMPC-adjusted revenues to calculate the master meter discount.[289]

We agree with TURN and PG&E that previous Commission decisions held that the costs to serve MHPs should form the basis of the estimate of the cost to provide submetering services, and that a residential class-based figure, such as that utilized by the line extension allowance, should not be used.[290]

We also agree with PG&E that the term "comparable services" as it appears in Public Utilities Code Section 739.5(a) should be interpreted as it was in previous Commission decisions, and that those decisions held that estimates of costs to serve MHPs should be used to define "comparable services." For example, D.04-11-033 stated that:

> "[Public Utilities Code Section] 739.5 applies to a limited set of residential users: tenants of submetered MHPs, in this case [citation]. It does not apply to the general body of ratepayers. It is reasonable to assume that 'comparable services' [as used by Public Utilities Code Section 739.5(a)] refers to service provided to directly served MHP customers of the utility, as opposed to residential ratepayers as a whole. As a result, the discount must be determined based on the average cost the utility incurs in directly serving MHP customers that is avoided by the utility when the tenant is served through a submeter."[291]

288 TURN-4 at 8-9.

289 PG&E-16, Chapter 3B at 60, citing D.11-12-053 and D.12-08-046.

290 TURN-4 at 9.

291 D.04-11-033 at 15-16.

In short, WMA has not shown why the master meter discount calculation methodology adopted by D.11-12-053 should be replaced by one based on the line extension allowance. This lack of an affirmative demonstration of the failing of the D.11-12-053 methodology, combined with the contradictions with existing Commission decisions and policy inherent in WMA's proposal to use a methodology based on the line extension allowance, lead us to reject WMA's line extension allowance methodology.

7.3.6. WMA's Proposal to Use a Recalculation of PG&E's Dataset as a Basis for Calculating the Master Meter Discount

WMA makes several proposals to adjust the data PG&E uses to calculate its proposed master meter discount. These include defining mobile homes as "single family" homes and utilizing the line length costs particular to such customers,[292] averaging A-6 and A-10 customer connection costs (presumably to find the cost to serve master meter customers),[293] using residential connection costs averaged from 2014 and 2017 rather than relying on 2017 data alone,[294] calculating the discount using PG&E's nominal RECC rather than a constant-dollar measure,[295] and calculating the DBA to reflect the lower usage of master meter tenants compared to directly metered mobile home customers.[296]

---

[292] WMA-1 at 33.

[293] WMA-1 at 38.

[294] WMA-1 at 36-37 (arguing that the significant variance between 2014 and 2017 data shows that the 2017 data is untrustworthy).

[295] WMA-1 at 38.

[296] WMA-1 at 39-40 (arguing generally that the sample of directly metered mobile home customers used by PG&E to calculate the DBA is not a representative sample master meter mobile home customers with respect to their usage patterns).

After making these adjustments to the PG&E dataset, WMA proposes that the master meter discount should equal $9.64/month/rental space.[297] The basis of this calculation is that PG&E's reported costs for a new residential connection on a net annual basis are $140.74/customer.[298]

TURN and PG&E object to each of WMA's proposed modifications to the PG&E dataset. First, TURN and PG&E argue that previous Commission decisions found that there is no obligation to regard mobile homes in master meter MHPs as single-family dwellings,[299] and further held that the costs to serve master meter subtenants are more comparable to the costs of serving multi-family customers than they are to the costs of serving single-family customers.[300]

TURN also objects to WMA's assertion that master meter MHPs have average service line lengths of 70.1 feet. TURN states that WMA's cost estimates for MHP lines are based on a report on MHPs in SCE's territory, not PG&E's; and furthermore that the Commission had previously found that master meter MHP service lengths were more comparable to multi-family service lengths than single-family service lengths.[301]

PG&E objects to WMA's proposal to average A-6 an A-10 customer connection costs as a proxy for the costs to serve the master meter itself. PG&E

---

[297] WMA-1 at 43.

[298] WMA-1 at 42.

[299] PG&E-16, Chapter 3B at 63-64 (noting that our view that MHP costs are more comparable to multi-family dwelling costs does not rewrite other state laws that define for their own purposes whether mobile homes should be single-family residences).

[300] TURN-4 at 11.

[301] TURN-4 at 12-13.

notes that D.11-12-053 held that A-10 connection costs should be used as a proxy for master meter connection costs, and that WMA has offered no evidence in this proceeding demonstrating why that finding should be changed.[302]

TURN argues against WMA's proposal to average residential class costs from 2014 and 2017 as the use of residential class-wide costs is not allowed for use in calculating the master meter discount per previous Commission decisions.[303] PG&E also argues against WMA's proposed averaging, arguing that variability of costs from one year to another does not in itself mean that the data is invalid.[304]

TURN further argues against WMA's proposal to use PG&E's nominal RECC in figuring the master meter discount rather than the constant dollar RECC. TURN believes doing so would double count inflation and inappropriately value assets. TURN further believes that using the nominal RECC will violate Public Utilities Code Section 739.5(a) by increasing the master meter discount to a level that would exceed PG&E's average cost to directly serve MHPs.[305]

PG&E states that WMA's proposal to use a nominal RECC "makes no sense" as a "nominal" RECC factor is by definition not a RECC factor at all.[306]

---

302 D.11-12-053 at 42; PG&E-16, Chapter 3B at 68.

303 TURN-4 at 13-14.

304 PG&E-16, Chapter 3B at 65 ("volatility of the MHP master meter discount from one case to another does not constitute an error").

305 TURN-4 at 16-17.

306 PG&E-16, Chapter 3B at 71.

PG&E also argues that a "nominal" RECC value has no place in a marginal cost-based calculation of the master meter discount, as applied by D.11-12-053.[307]

With respect to WMA's proposed adjustment to the DBA, PG&E generally argues that its sampling approach already accounts for two of the concerns raised by WMA – that master meter customers generally have lower usage than directly metered MHP customers, and that CARE master meter customers generally have higher usage that non-CARE master meter customers.[308]

On WMA's third proposal to adjust the DBA calculation, PG&E granted that some adjustment to the presumed CARE saturation of the master metered population was warranted, and proposed in their rebuttal testimony a refined CARE saturation amount in response to WMA's concerns.[309]

WMA's proposal to recalculate the master meter discount based on their modifications to PG&E's dataset is rejected. We do not believe that WMA has made a compelling case that mobile homes in master metered MHPs should be treated as single-family residences for the purpose of calculating the master meter discount. We reiterate our previous findings that the costs to serve master metered MHPs are more comparable to the costs of serving multi-family residences than they are to the costs of serving single-family residences.[310] The record in this proceeding does not offer a compelling reason for changing that

---

[307] PG&E-16, Chapter 3B at 72.

[308] PG&E-16 at 3A-2.

[309] PG&E-16 at 3A-2.

[310] TURN-4 at 11-13.

finding.[311] We also agree with PG&E that the A-10 connection costs should continue to be used in the master meter discount calculation, given that WMA has provided no evidence why an existing change to that methodology is warranted.

Variances in connection cost data between 2014 and 2017 is not evidence, in and of itself, that the 2017 data is unreliable and should be averaged. We also find that using average residential connection costs to calculate the master meter discount is not in accord with our previous decisions. As we stated in a previous decision on this topic, "[u]tilizing the costs of the utility to serve the entire residential class to set the discount for submeter service [to mobile home park] tenants would distort and undermine any reasonable effort to calculate a realistic discount."[312]

Using a nominal RECC cost of capital figure is not necessary in order to calculate the master meter discount in a manner that conforms to the requirements of Public Utilities Code Section 739.5(a). The law only requires that PG&E's avoided costs to serve master metered customers be used as a cap on the discount itself.[313] The cost of providing master meter service does not necessarily need to include a nominal RECC cost of capital figure, and we decline to find that the law requires it. As a more general matter, we reiterate our previous holding in D.12-10-004 that the master meter discount "is based on the utility's

---

[311] TURN-4 at 13. We agree with TURN that we have consistently found that the average service length for MHPs is of a length comparable to multi-family service lengths, and that WMA has presented no evidence to overturn these findings.

[312] TURN-4 at 14, citing D.12-08-046 at 9, citing D.05-04-031 at 6.

[313] TURN-4 at 3, 16.

avoided costs pursuant to Public Utilities Code Section 739.5(a). MHP owners/operators are not legally entitled to receive a discount any higher than utility avoided costs."[314]

As we held previously in this decision, we agree with TURN that WMA's usage of a residential class average connection cost as the basis for the master meter discount calculation is not in accord with our previous decisions and that WMA's proposal should therefore be rejected.[315] We find that as WMA used a residential class average connection cost for the basis of its total calculation under this proposed methodology, and such class-average costs are not appropriate to use in this fashion, WMA's proposal would be rejected even if this was the only reason for doing so.

WMA's request to modify the DBA figure based on a purported error in the sample used by PG&E is rejected. PG&E's sample of directly metered MHPs to use in calculating the DBA has been used for several years, and while WMA speculates that the usage patterns of master metered mobile home customers are distinct from the sample population's usage, there is not support in the record for the argument that the difference (if it exists) is large enough to invalidate the sample itself.

[314] D.12-10-004 at 8-9.

[315] TURN-4 at 18; D.05-04-031 at 6 ("[u]tilizing the costs of the utility to serve the entire residential class to set the discount for submeter service [to mobile home parks] tenants would distort and undermine any reasonable effort to calculate a realistic discount").

7.3.7. WMA's Proposal to Use an Adjusted Revenue Allocation to the ET Rate Schedule as a Basis for Calculating the Master Meter Discount

WMA's final alternative methodology is to adjust the revenue allocation to the ET rate class to reflect "its actual cost responsibility" per the revenue allocation process approved by the Commission.[316] WMA claims this is necessary in the event the Commission decides to base the calculation of the ET discount on multi-family connection costs. WMA implicitly recognizes that we do not treat ET customers as their own class for revenue allocation purposes, but argues that we should do so as the master meter discount calculation methodology adopted by D.11-12-053 applies master meter-specific marginal cost estimates.

TURN argues against this approach stating that it does not comply with the Commission's approved methodology for calculating the master meter discount in D.11-12-053, and that it includes an EPMC-based adjustment to the ET discount by reallocating scaled revenue requirements.[317]

We agree with TURN that the recommendation of WMA to use an adjusted revenue allocation to customers on the ET rate schedule does not comply with our methodology for calculating the ET discount in D.11-12-053 and that it would include EPMC-scaled costs in contradiction of previous Commission decisions on this matter.

Further, even if we did not agree with TURN, WMA's argument that the master meter discount methodology justifies the creation of virtual class for

[316] WMA-1 at 43.

[317] TURN-4 at 19.

revenue allocation purposes is not adopted. The master meter discount methodology is just that – a methodology for calculating a discount required by statute. It is not a method by which we determine class status for revenue allocation purposes.

7.3.8. WMA's Proposal to Clarify Responsibility for Excavation and Replacement Costs and Whether to Include Such Costs in the Master Meter Discount Calculation

WMA proposes in its opening testimony that the Commission clarify which party holds the responsibility for excavation and replacement costs under PG&E's Electric Rules,[318] stating that PG&E has provided contradictory advice to WMA on this issue over the years.[319] We find that this request for a clarification of the responsibility for excavation and replacement costs under PG&E's Electric Rules is beyond the scope of the issues to be addressed in this proceeding, as recited in Section 1 above. We therefore decline to clarify responsibilities for excavation and replacement costs under PG&E's Electric Rules in this decision.

However, we will consider WMA's argument that excavation and replacement costs should be included in the calculation of the master meter discount, as the issue of the reasonableness of PG&E's master meter discount proposal is within the scope of this proceeding. The upshot of WMA's argument is that such costs should be included in the master meter discount as it would be the master meter customer's responsibility to undertake such activities if their submetering system was ever in need of replacement. WMA argues that PG&E

---

[318] WMA-1 at 47.

[319] WMA-1 at 44.

can cover such costs for directly serviced MHP systems through rates with no costs passed through to the directly-metered MHP owner.[320] WMA implicitly argues that master meter MHP owners should be treated similarly and allowed to avoid costs for excavation and replacement by using the master meter discount to cover such costs.[321]

TURN argues that this issue was previously addressed in D.11-12-053 and that the Commission held that explicitly adding replacement costs to the master meter discount would result in double counting as the RECC factor component of the discount's methodology already included replacement costs.[322] PG&E makes a similar argument.[323]

We agree with TURN and PG&E that explicit inclusion of excavation and replacement costs in the calculation of the master meter discount is unjustified. We reiterate our previous finding from D.11-12-053 that such costs are already accounted for in the master meter discount calculation methodology, and explicitly including them would result in double counting.[324] WMA's arguments on this point are therefore rejected.

7.3.9. WMA's Proposal to Update Special Condition 9 of the ET Tariff

WMA argues in their testimony that we should order PG&E to update the language appearing in Special Condition 9 of the ET tariff sheet to 1) state that

---

[320] WMA-1 at 45-46.

[321] WMA-1 at 47.

[322] TURN-4 at 20.

[323] PG&E-16, Chapter 3B at 91-94.

[324] D.11-12-053, Finding of Fact 31.

the term "electric submetered system" is defined in Attachment A of D.04-04-043, and 2) that excavation and substructure costs are recoverable in rents.[325]

PG&E argues that these requests by WMA were previously litigated in its 2011 GRC Phase II proceeding and that PG&E previously opposed these proposals.[326] TURN argues that we should reject WMA's proposals as well. TURN first argues that WMA misreads D.04-04-043 and that D.04-04-043 explicitly left undisturbed the conclusions of D.95-02-090, meaning that there is no reason to change the tariff language referring to that 1995 decision.[327]

TURN then takes an affirmative position that the Commission should change the language in Special Condition 9 to state that a "[v]iolation of Special Condition #9" will result in removal of any submetering costs that were collected in rent.[328] TURN also recommends that we equip our consumer affairs branch with an expedited decision template to use when we find that a MHP owner has violated Special Condition 9.[329] TURN urges that we have our enforcement staff improve its guidance to rent control boards on how to apply our decisions and Public Utilities Code Section 739.5(a).[330] TURN also recommends a workshop

---

325 WMA-1 at 51.

326 PG&E-16, Chapter 3B at 95-97.

327 TURN-4 at 24-25.

328 TURN-4 at 33.

329 TURN-4 at 33.

330 TURN-4 at 34-35, citing hearsay of purported Commission communications to the Chula Vista Rent Control Commission.

process to develop guidance for rent control boards on how to interpret Commission decisions on this matter.[331]

Neither of WMA's requests is within the scope of this proceeding, as defined in Section 1 above. The questions of how the ET tariff sheet defines the "electric submetered system" and whether it clarifies that certain costs are recoverable in rents do not impact the value of the master meter discount and therefore are not relevant to the question of whether the rate designs proposed by PG&E in this proceeding are reasonable. TURN's requests are also outside the scope of this proceeding and are rejected as well.

We note that, even if the requests by WMA and TURN were within the scope of this proceeding, the tariff language at issue was approved by the Commission in light of earlier decisions, and both parties had an opportunity to protest the advice letters proposing the tariff language at the time they were submitted to the Commission.[332] The Commission approved the tariff's current language, in spite of protests (if any), and we have no reason to disturb that prior determination in this decision. WMA's suggestion that rent control boards are confused by the tariff's language – which TURN argues is both false[333] and true[334] – is not a sufficient reason to change the tariff language contrary to a previous

---

331 TURN-4 at 35.

332 TURN, somewhat ironically, cites this procedure when alleging that WMA is misinterpreting Commission policy before rent control boards (TURN-4 at 32).

333 TURN-4 at 32 ("TURN believes that Special Condition #9 is clearly worded to provide guidance to park owners and rent control jurisdictions on how to comply with PU Code [Section] 739.5(a)").

334 TURN-4 at 35 (recommending development of a template that can be used to "guide rent control authorities and their staff when questions arise from local officials about the proper interpretation of prior Commission decisions").

Commission determination that it was compliant with Commission decisions and orders.

7.3.10. Master Meter Discount Adopted by This Decision

In light of our rejection of alternative methodologies for calculating the master meter discount, we adopt a master meter discount proposed by PG&E and utilizing our master meter discount calculation methodology adopted in D.11-12-053. We find that this methodology is consistent with Public Utilities Code Section 739.5(a).

The base discount should be set at a level of $5.16/month/tenant space, in light of the estimates of PG&E's avoided costs for not serving submetered tenants of master meter customers.[335] This figure shall be adjusted before final implementation to account for changes to PG&E's RECC calculation that result from the Tax Cuts and Jobs Act, as requested by TURN.[336] The line loss adjustment shall be set at a level of $2.18/month/tenant space.[337]

With respect to the DBA, which was the subject of considerable debate, we find it should be set at a level of $5.37/month/tenant space to reflect the methodology for calculating the DBA used in prior decisions on this topic.[338] We

---

335 PG&E-47. TURN agreed to a base discount of $5.16 in their briefing (TURN Reply Brief at 2).

336 TURN Opening Brief at 2; TURN Reply Brief at 12.

337 PG&E-47 contains a table of these updated figures based on the most current data available in PG&E's rebuttal testimony. PG&E-16, Chapter 3B at 3 also describes these figures. The line loss adjustment figure was not opposed in this proceeding.

338 PG&E-47 reveals this figure for the DBA if current data is used and a presumed CARE saturation rate of approximately 60% is utilized, as was done in the past. This also includes a $0.36 reduction in the DBA that PG&E grants is justified in light of WMA's testimony (PG&E Opening Brief at 13).

do not choose to eliminate the DBA, as proposed by WMA for the first time in briefing,[339] or to radically adjust the CARE saturation assumed when calculating the DBA, as proposed by PG&E and TURN in their testimony and briefing.[340] Instead, we adopt a calculation of the DBA using the previous CARE saturation rate as reflected in PG&E Exhibit 47.

PG&E shall construct an ET master meter discount using these figures. PG&E shall calculate an ES master meter discount figure based on the ET discount using the methodology proposed in its testimony and briefs.[341]

7.4. Legacy TOU Rates for RES-BCT Customers

As part of the TOU settlement, all customers participating in the RES-BCT program may be required to take service on new rates that would diminish the price of energy during peak solar production hours over time. The Counties of San Joaquin and Santa Clara, representing the interests of RES-BCT customers generally, opposed the terms of the TOU settlement as they apply to RES-BCT customers on equity grounds. They seek an alternative rate scheme that would fix the price of energy during peak solar production hours for several years. PG&E objects to this proposal and recommends that RES-BCT customers take service under the terms of the TOU settlement.

---

339 WMA Opening Brief at 1, 6. We reiterate our conclusion from D.11-12-053 that the DBA is warranted to ensure that master meter customers do not receive excess revenues from billing tenants at higher-priced tiers than occurs for the tiered usage billed at the master meter level (D.11-12-053 at 41).

340 PG&E Opening Brief at 8; TURN Opening Brief at 3. *See also* WMA Opening Brief at 15-16 for a discussion of PG&E's proposal from WMA's perspective.

341 PG&E Opening Brief at 7 summarizes the ES calculation methodology.

We find that the arguments of the Counties of San Joaquin and Santa Clara have merit, although we do not adopt their proposal for fixed rates or TOU periods. Instead, we apply modified terms of the TOU settlement to RES-BCT customers so that they face a similar reduction in the price of energy as that faced by non-RES-BCT legacy solar customers. There are essential differences in the way in which RES-BCT customers and non-RES-BCT customers receive financial incentives through rates to install and operate renewable energy systems. Consistent with principles of equity and the overall policy of the state of California to support customer-sited renewable energy development, the TOU settlement must account for these differences and treat RES-BCT customers in such a way as to create equal treatment with respect to the reduced financial incentives to install and operate customer-sited renewable energy systems.

AB 2466 (2008, Laird) created the RES-BCT program, codified at Public Utilities Code Section 2830. AB 512 (Gordon, 2011) made a modification to the program's project size limit. Similar to the net energy metering (NEM) program, RES-BCT requires the customer's utility to issue bill credits for renewable energy exported to the grid by the customer at a price defined by the customer's retail electricity rate. The RES-BCT program differs from the NEM program in that an RES-BCT customer only receives a bill credit equal to the generation portion of the retail rate,[342] rather than most of the whole retail rate (including non-generation components) credited to NEM customers. The County of San Joaquin cites to this differential treatment in its testimony, asserting that RES-BCT customers receive credits of approximately 50% of the full retail rate,

342 Public Utilities Code Section 2830(a)(2).

while new NEM customers receive credits of approximately 90% of the full retail rate.[343]

In its testimony served on December 2, 2016, PG&E proposed to revise its A-6 rate schedule to move the peak summer period from 12 noon to 6 p.m. on non-holiday weekdays to 5 p.m. to 10 p.m. during all days.[344] PG&E also proposed to change the total energy rate paid by A-6 customers for power consumed between 3 p.m. and 5 p.m. on non-holiday weekdays in the summer from 55 cents/kWh to 24 cents/kWh.[345] The generation component of this total energy rate would change from 36 cents/kWh to 10 cents/kWh.[346]

Under PG&E's initial A-6 rate proposal, NEM customers would experience an approximate 56% reduction in their compensation for renewable energy exported to the grid between 3 p.m. and 5 p.m. in the summer, while RES-BCT customers would experience an approximate 72% reduction in compensation for the same energy. The drop in compensation for energy exported from 12 noon to 3 p.m. on non-holiday weekdays was even greater – 65% for NEM customers and 75% for RES-BCT customers – due to the proposed conversion of 12 noon to 3 p.m. from a peak period to an off-peak period. Finally, PG&E proposed to reduce the number of summer months in which these prices would be available from six to four.[347]

---

343 County of San Joaquin Opening Testimony at 23.

344 PG&E-9, Chapter 12 at 7.

345 PG&E-8, Chapter 5 at 5.

346 PG&E-8A at B-10.

347 PG&E-9, Chapter 12 at 7.

The County of San Joaquin served testimony on May 19, 2017, that opposed PG&E's proposal to change its retail rates, specifically rate schedule A-6.[348] They testified that the PG&E's proposed changes would "kill RES-BCT."[349] They also submitted evidence that the net present value of their investment in RES-BCT renewable energy systems, and the investments of the County of Santa Clara and the California State University in similar systems, would plummet under the revised A-6 rates proposed by PG&E.[350] They testified that the changes to the A-6 rate proposed by PG&E in its testimony could not be reasonably anticipated given historic trends in A-6 rate changes.[351]

The County of San Joaquin initially proposed placing RES-BCT customers in their own rate class, and subject to a rate that "maintains existing levels of [RES-BCT] project viability" with a fixed set of TOU periods and prices based on current A-6 rates.[352] On December 8, 2017, the County of San Joaquin served supplemental testimony that clarified their requested relief to include a 10-year period where the current A-6 TOU periods and rates would be fixed for current RES-BCT projects.[353] On January 25, 2018, the County of San Joaquin and the County of Santa Clara jointly served rebuttal testimony that added a request for a "stable alternative" rate for non-legacy RES-BCT customers for a period of at

---

348 County of San Joaquin Opening Testimony at 2-3.

349 County of San Joaquin Opening Testimony at 3.

350 County of San Joaquin Opening Testimony at 7-9.

351 County of San Joaquin Opening Testimony at 11.

352 County of San Joaquin Opening Testimony at 29-30.

353 County of San Joaquin Supplemental Testimony at 9.

least 20 years.[354] On February 22, 2018, the County of San Joaquin and the County of Santa Clara jointly served comments on the motion by PG&E for adoption of the TOU settlement. These joint comments continue to argue against the imposition of the TOU settlement rate design on RES-BCT customers.

PG&E responded to the County of San Joaquin's opening and supplemental testimony in its rebuttal testimony. In that testimony, PG&E argued that the RES-BCT statute forbids calculating the bill credit using anything other than the generation component of an otherwise applicable rate schedule.[355] PG&E cites the TOU settlement as the appropriate set of tariffs for RES-BCT customers, and argues that rates as modified by the settlement comply with the requirements of D.17-01-006 for existing RES-BCT customers.[356] PG&E also argues that the challenges faced by public agencies as developers of solar projects were considered by D.17-01-006 and factored into that decision's determination of how to structure legacy TOU periods for legacy solar customers.[357]

As discussed previously in this decision, we find that the TOU settlement's treatment of legacy solar customers complies with the mandates and guidelines of D.17-01-006 and other applicable law. D.17-01-006 thoughtfully considered

---

354 Rebuttal Testimony of County of San Joaquin and County of Santa Clara at 4. This rebuttal testimony also argued that the proposed changes to A-6 peak periods should be rejected by the Commission. As we accept the settlements adopting the new peak periods, this argument is rejected.

355 PG&E-16, Chapter 5 at 2.

356 PG&E-16, Chapter 5 at 4.

357 PG&E-16, Chapter 5 at 9-10. We also note that PG&E-49 demonstrates that there are nearly one thousand government-sponsored solar projects on the A-6 rate that have taken service under NEM rather than RES-BCT, and that the particular impacts of TOU peak periods transitions on governments were therefore encompassed by D.17-01-006.

the impacts of peak period changes on legacy TOU customers, including public agencies such as public school districts, when constructing its requirements for rate designs such as that created by the TOU settlement. We therefore agree with PG&E that the particular financial concerns faced by public agencies are adequately addressed by the TOU settlement as it complies with the requirements of D.17-01-006.[358] We therefore reject the proposal of the Counties of San Joaquin and Santa Clara to establish a rate option that allows existing A-6 RES-BCT customers to keep their existing peak-to-off-peak price ratios for a 10-year period, and for a "stable alternative… rate for a period of at least 20 years for all RES-BCT customers, regardless of whether or not" they are legacy TOU customers.[359]

The TOU settlement represents an effort by many parties to this proceeding, including consumer and renewable energy development advocates, to craft a transition in TOU peak periods and rates that allows for customers with renewable energy systems to recoup a reasonable amount of their investment. The TOU settlement significantly modifies the original 2016 PG&E proposal with respect to the A-6 rate schedule. For example, the TOU settlement provides that solar customers that are eligible for legacy treatment under D.17-01-006 may take service under legacy rate schedules that retain the current TOU periods, including the peak period of 12 noon to 6 p.m.

However, comments filed by the Counties of San Joaquin and Santa Clara on the motion seeking adoption of the TOU settlement clearly identify the TOU

---

358 *See also* PG&E Opening Brief at 46-48.

359 Comments of County of San Joaquin and County of Santa Clara on Motion to Adopt TOU Settlement at 4.

settlement's inequitable treatment of RES-BCT customers as compared to NEM customers. The comments state that:

> "The Settlement Agreement does not consider that RES-BCT solar customers were already receiving a substantially smaller bill credit than NEM customers under current rates, and that the proposed transition rates create a proportionately greater reduction in those credits than for NEM customers."[360]

The County of San Joaquin previously identified this issue in its supplemental testimony, where they state that a reduction in the generation component of the potential bill credit has less than half the impact on NEM customers that it has on RES-BCT customers.[361] They argue that the Commission should ensure that RES-BCT and NEM customers are equally protected as TOU periods change.[362]

We agree with the County of San Joaquin that this principle should guide our decision-making on this issue in this proceeding and that the TOU settlement should address the different bill credit characteristics of the RES-BCT program vis-à-vis the NEM program. We do not agree that the TOU settlement need consider the additional project costs borne by RES-BCT customers as compared to NEM customers as those extra costs are imposed by statute and were well-known to RES-BCT customers during project development.

---

360 Comments of County of San Joaquin and County of Santa Clara on Motion to Adopt TOU Settlement at 4, *see also* 6-7. County of San Joaquin and County of Santa Clara Opening Brief at 17 makes the same argument.

361 County of San Joaquin Supplemental Testimony at 12.

362 County of San Joaquin Supplemental Testimony at 9. While the County of San Joaquin only refers to the need for equal treatment between RES-BCT and Virtual NEM customers, in principle that means ensuring equal treatment between RES-BCT and all NEM customers. Comments of County of San Joaquin and County of Santa Clara on Motion to Adopt TOU Settlement at 9.

Therefore, while it is appropriate to apply the terms of the TOU settlement to RES-BCT customers, those terms must ensure equal treatment between NEM and RES-BCT customers with respect to their diminished returns for the generation of renewable energy. PG&E must ensure that legacy A-6 RES-BCT customers, as a class, experience no greater percentage annual decreases in their effective benefits than those received by legacy A-6 NEM customers, as a class, for the same energy produced at the same time of day on the same otherwise applicable rate schedule.[363] This does not mean that NEM legacy solar customers and RES-BCT legacy solar customers must receive the same absolute amount of bill credit for each kWh generated, but that the rate of decrease in that credit for the same energy produced at the same time of day on A-6 from year-to-year must be the same. PG&E is authorized to take the steps necessary to ensure this occurs, including manual billing of RES-BCT benefiting accounts.

For the sake completeness, we clarify that RES-BCT customers that do not qualify for legacy solar customer status may not take advantage of this revision to the TOU settlement rates, as the TOU settlement does not apply to such customers. RES-BCT customers that do not qualify for legacy solar customer status must take service on otherwise applicable rate schedules, and like NEM customers that are not legacy solar customers they receive no special rate design treatment.

363 As a matter of law, we agree with County of San Joaquin and County of Santa Clara that, the "rate schedule applicable to the account" referred to in Public Utilities Code Section 2830(c) does not require RES-BCT customers to take service on the same TOU settlement rate (or any other rate) as other non-RES-BCT legacy solar customers (County of San Joaquin and County of Santa Clara Reply Brief at 16). A modification to the TOU settlement rate applicable to RES-BCT customers as described here is permitted by Section 2830(c) as we define it here as the "rate schedule" that shall be "applicable" to legacy RES-BCT projects.

In response to arguments made by PG&E and CLECA, we clarify that we do not find that this adjustment of the TOU settlement generation rates for RES-BCT customers will result in cost-shifting to non-RES-BCT customers.[364] Because the solution we adopt in this decision results in a slight change to the TOU settlement generation rates for RES-BCT customers, and requires RES-BCT customers' benefiting accounts to continue paying the same distribution and transmission charges as all other customers,[365] and because RES-BCT customers represent a very small percentage of legacy TOU customers generally,[366] we do not believe it results in a quantifiable cost shift to other customers.[367]

7.5. Agricultural Class Sales Forecasting

The Agricultural Parties (AECA and CFBF) generally request that the Commission develop a "mechanism" to address past overcollections and undercollections from the agricultural class.

---

[364] Note that we do not necessarily agree with PG&E that Public Utilities Code Section 2830(d) requires that RES-BCT customers take service on the same rate as any other bundled customer in order to avoid cost shifts. Indeed, the TOU settlement itself presumes that RES-BCT customers will not violate Public Utilities Code Section 2830(d) by taking service on TOU settlement rates that do not signal the same marginal cost responsibilities as non-TOU settlement rates.

[365] County of San Joaquin and County of Santa Clara Opening Brief at 25, noting that the limitation of RES-BCT credits to the generation rate ameliorates against any claim of cost shifting. In other words, RES-BCT customers already pay their full share of distribution, transmission and public purpose program charges.

[366] PG&E-49 demonstrates that RES-BCT customers make up a very small portion of overall A-6 NEM customers.

[367] County of San Joaquin and County of Santa Clara Opening Brief at 24-28. The County of San Joaquin and County of Santa Clara also point out at 25 of their Opening Brief that specific administrative and implementation fees are created for RES-BCT customers to ensure that their administrative costs are not shifted to other customers.

7.5.1. The Agricultural Class Routinely Faces Inaccurate Sales Forecasts

It appears that PG&E and Agricultural Parties agree that actual electricity sales for the agricultural class deviate substantially from forecasted sales for the class on a regular basis, and that the deviation is driven by the availability of surface water for irrigation.[368] This suggests that the sales forecasting mechanism for the agricultural class is flawed and should be refined such that the forecasts are more accurate.

Developing any other mechanisms beyond improved forecasting in the context of this proceeding is difficult for the reasons mentioned by PG&E in its opening brief. Namely, this proceeding does not produce sales estimates for PG&E's classes that would form the baseline for determining whether an alleged overcollection or undercollection occurred. As PG&E notes, these forecasts are normally considered in its Energy Resource Recovery Account (ERRA) proceeding on an annual basis.[369]

We do not establish a specific methodology for forecasting agricultural sales here, as that issue is better suited for litigation in PG&E's ERRA proceeding. But we do find the sales forecasting mechanism for the agricultural class is flawed and should be refined such that the forecasts are more accurate. We therefore order PG&E to propose an improved sales forecasting mechanism for the agricultural class in its next ERRA proceeding, and to involve the Agricultural Parties in the development of that improved mechanism.

---

[368] MC/RA Settlement, Attachment 2 at 1.

[369] PG&E Opening Brief at 59.

7.5.2. Reallocation of Previously Collected Revenue

In their testimony, the Agricultural Parties seek to quantify a "cost shift" to and from the agricultural class going back to 2014, with the implied objective of correcting "bill errors" per Electric Rule 17.1 once that quantification occurs, potentially resulting in refunds or other such remedies for agricultural customers.[370] While it is not clear that the Agricultural Parties are seeking this remedy, PG&E supplied testimony and briefing assuming that is was the intent of Agricultural Parties to do so.[371]

PG&E is correct that reallocation of revenue previously collected from agricultural class members as hypothesized by the Agricultural Parties would constitute retroactive ratemaking as a matter of law, and that Electric Rule 17.1 does not contemplate bill adjustments based on retroactive quantification of cost shifts between classes. We therefore decline to entertain the development of any mechanisms to address past alleged overcollections or undercollections from the agricultural class, as requested by the Agricultural Parties.[372] This includes declining to order PG&E to quantify any cost shifts that may have occurred in the past. However, as described above, we seek to address the sales forecasting issue for the agricultural class on a prospective basis.

---

[370] Agricultural Parties-1 at 30.

[371] PG&E-16, Chapter 2 at 2.

[372] Agricultural Parties Opening Brief at 1.

7.5.3. Impact of Sales Forecasting on Revenue Allocation

While it is somewhat unclear from the testimony and briefing of the Agricultural Parties, we consider for the sake of argument that the Agricultural Parties are also seeking a revised form of revenue allocation for the agricultural class based on conditions other than those that occur during a "normal" water year.[373] The Agricultural Parties lay the theoretical groundwork for such a measure when in their reply brief they state that "the status quo, which fails to address the revenue requirement changes that stem from the sales variance [from the forecast], affects the revenue allocation for all customer classes depending on whether the water availability drives an under or overcollection from Agricultural customers."[374]

The MC/RA settlement in this proceeding excludes considerations of the Agricultural Parties' claims of deviations between the estimated forecast for agricultural class responsibility and the revenue actually collected from the agricultural class.[375] This explicit exclusion begs the question of why the Agricultural Parties would settle on a revenue allocation to the agricultural class of $1,092,990,616 if they felt that the figure was derived from an inaccurate methodology.

---

373 Agricultural Parties-1 at 12. Agricultural Parties Opening Brief at 2 notes that while they do not seek a specific request for revenue adjustments at this time, they anticipate that "proper quantification" of alleged cost shifts to and from the agricultural class back to 2014 may support a revenue adjustment in the future.

374 Agricultural Parties Reply Brief at 5.

375 MC/RA settlement at 19.

Faced with a specific settlement by the Agricultural Parties on the revenue allocation for the agricultural class and the apparent desire by the Agricultural Parties to litigate the basis for the determining that revenue allocation, we choose to accept the settlement on the revenue allocation for the agricultural class. We do not employ an alternative method of calculating the revenue allocation for the agricultural class to respect the integrity of the MC/RA settlement. We consider the arguments surrounding the appropriate revenue allocation for PG&E's agricultural class to be settled for this GRC Phase II cycle.

7.5.4. Agricultural Parties Arguments that PG&E's Data is Flawed

In general, the Agricultural Parties argue that PG&E's data used to generate its Agricultural Class Balancing Account Study demonstrates flaws and may be unreliable.[376] However, they also note that "the Agricultural Parties do not contend that any of the individual data irregularities highlighted reflect a certain error, just that each is irregular enough to raise deep concerns about the underlying data and collectively they suggest a high probability of error."[377]

We decline to find that there is a "high probability" of error in PG&E's dataset used to generate its Agricultural Class Balancing Account Study. Without more certainty that PG&E's data itself is flawed, in spite of the "anomalies"[378] in relationships between data that the Agricultural Parties perceive, we cannot arrive at that conclusion. In any event, the Agricultural Parties have settled on a specific revenue allocation for the agricultural class in

---

[376] Agricultural Parties Opening Brief at 5.

[377] Agricultural Parties Opening Brief at 7.

[378] Agricultural Parties Reply Brief at 14.

this proceeding. In itself, this outcome suggests that the PG&E data presented in this proceeding is sufficient to arrive at an equitable allocation of revenue in the eyes of the Agricultural Parties in spite of their concerns.

8. Conclusion

For the most part, this decision accepts settlements among the parties to this proceeding that make significant changes to PG&E's rate designs. These changes include creating a 4 p.m. to 9 p.m. peak period for most non-residential customers and a 5 p.m. to 8 p.m. peak period for agricultural customers, creating a super off-peak period in the spring to increase utilization of renewable energy generation resources, and shrinking PG&E's summer season to a four month period of June through September.

However, this decision proposes modifications to certain elements of the settlement related to rate designs for medium and large commercial customers, as the settlement's terms on these elements are unreasonable in light of the proceeding's record and previous Commission decisions. The proposed modifications concern the cost basis for the distribution demand charges proposed by that settlement. We propose a revised cost basis and attendant rate design for those demand charges.

This decision also describes our general concern with PG&E's approach to rate design in this proceeding, and mandates elements that PG&E's future rate design applications must include.

This decision resolves disputed areas of fact and law where the parties could not reach agreement. We reject the proposal for a particular rate design for former E-37 customers, the proposal to revise revenue allocations for the agricultural class, and the proposals for alternative methodologies for calculating the master meter discount. We do find that it is reasonable to apply a particular rate design to RES-BCT customers, to create an Option S rate for certain energy storage customers, and to address sales forecasting errors that frequently afflict the agricultural customer class.

9. Outstanding Procedural Matters

The Commission affirms all rulings made by the assigned Commissioner and assigned ALJ. All motions not previously ruled on are deemed denied.

10. Comments on Proposed Decision

The proposed decision of ALJ Doherty in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on ____________, and reply comments were filed on _____________ by ___________________.

11. Assignment of Proceeding

Carla J. Peterman is the assigned Commissioner and Patrick Doherty is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. A utility's revenue allocation has a direct effect on the average rate for electricity faced by a customer in the class, because average rates are found by dividing the revenue allocation by the expected sales for that class.

2. The parties to the MC/RA settlement in this proceeding were concerned with far more than simply marginal cost responsibilities for each class, and eventually the settling parties chose not to use any single party's proposed marginal costs. Instead, the parties created "black box" (i.e., artificial) marginal cost values that would lead a computer model to produce their desired revenue allocation outcome.

3. MC/RA settling parties representing all customer groups presented testimony on revenue allocation issues.

4. MC/RA settling parties worked diligently and focused on multiple simulations outlining all litigated positions, and ultimately agreed to focus on rate impacts rather than marginal cost responsibility.

5. The result of the MC/RA settlement is a balanced settlement for all ratepayers.

6. The MC/RA settlement results in very mild changes in revenue allocation compared to PG&E's existing revenue allocation, which minimizes the impact of the MC/RA settlement on average rates.

7. The data PG&E used in the instant proceeding to propose changes to its summer season and TOU period definitions are based on PG&E's forecasted ANL for the year 2020. This 2020 ANL forecast was used to produce marginal generation cost estimates, by hour, for 2020. PG&E then defined "high cost hours" as those in either the Top 100 or Top 250 of the forecasted marginal generation cost hours for 2020. PG&E also examined the Top 5% of forecasted marginal generation cost hours to refine TOU periods once established using the Top 100 and Top 250 hours. Additionally, PG&E looked to the peak hours of load on their distribution circuits, in addition to peak hours for marginal generation costs, when determining the appropriate summer part-peak period in accordance with the principles outlined in D.17-01-006.

8. PG&E's analysis of their marginal generation costs by month showed that the majority of PG&E's highest cost hours are forecasted to occur in June – September 2020. PG&E's analysis also showed that May and October see less than one percent of the highest cost hours over the course of that forecasted year.

9. PG&E's testimony reflects that the month of June has considerably fewer high cost hours compared to the months of July – September, and on a Top 250 hour-basis June has a smaller percentage of high cost hours as compared to October, November, or December.

10. Party testimony demonstrated reasonable grounds for disagreement concerning the proper peak and part-peak hours for PG&E.

11. The narrow agricultural peak period of 5 p.m. to 8 p.m. proposed by the parties falls within the proposed 4 p.m. to 9 p.m. peak period for non-agricultural customers. The 5 p.m. to 8 p.m. peak period is also supported by parties representing agricultural customers.

12. Agricultural customers have specific operational constraints that favor an early daily end to the peak period. Parties to the agricultural settlement testified that an earlier end to the peak period is necessary for agricultural customers so that they may safely inspect their equipment before the start of the off-peak period. The daylight still available at 8 p.m. during the summer would apparently allow for safe inspections.

13. It is evident that PG&E and the settling parties either held or dramatically reduced the differential between peak and off-peak summer energy charge prices for PG&E's non-residential TOU customers, with the exception of A-1 and A-10-T customers.

14. With the exception of the E-20-T schedule, PG&E and the settling parties propose to substantially reduce the price premium for peak period demand charges, and in some cases propose peak period demand charge prices that are below the non-coincident demand charge price.

15. Non-coincident demand charges incentivize customers to flatten their load, but given high penetration of solar resources, solar-following loads are becoming

more desirable to avoid curtailing renewable resources and may be less costly to serve than customers with flat loads.

16. Non-coincident demand charges can discourage beneficial energy use, such as electric vehicle fleet charging (overnight or during hours with high solar generation), or Reverse Demand Response to encourage customers to use renewable energy that might otherwise be curtailed due to over-generation conditions.

17. The flattening of price differentials proposed by PG&E in the various settlements for nearly all of its non-residential TOU customers in this proceeding will have several detrimental effects, including: sending flawed price signals to PG&E's customers, incenting inefficient use of electricity that imposes costs on society through emissions of greenhouse gases, and overcharging customers for off-peak electricity.

18. We recently ordered SDG&E to file a transmission study to examine the appropriate allocation of transmission costs between non-coincident demand charges and system peak demand charges to be filed at FERC prior to the next San Diego Gas & Electric Company Phase II General Rate Case.

19. Recently, we adopted a multi-party stipulation in SCE's Transportation Electrification proceeding (A.17-01-020, et al.) directing SCE to file a request at FERC to modify certain retail transmission rates (now 100% non-coincident demand charges) to include a 30% volumetric TOU component. The adopted stipulation (subject to FERC approval) allocates 30% of transmission costs to volumetric rates and 70% to demand charges, and SCE will update this allocation once it completes a transmission cost study during SCE's current GRC Phase II.

20. PG&E, ORA, SBUA, and other parties to the SLP settlement bargained during negotiations to reduce PG&E's originally proposed increases in customer charges for the SLP classes.

21. No party chose to litigate the A-1 TOU energy charges and structure. ORA and SBUA were broadly supportive of PG&E's originally proposed A-1 TOU energy charges in their testimony.

22. The illustrative A-1 STORE rate appears to provide significant rate differentials between peak and off-peak pricing throughout the year that may help incent energy storage operation that leads to reductions in GHG emissions.

23. Because the A-1 STORE rate differs substantially from PG&E's original proposal for an A-1 rate specifically designed for energy storage customers, we presume that there was substantial give-and-take between the settling parties on the issue of how to design the A-1 STORE rate.

24. Various other elements of the SLP settlement appear to be non-controversial and widely agreed to by the SLP settling parties. Our review of the record of this proceeding indicates no reason why these elements of the SLP settlement should be rejected.

25. While California unemployment rates have generally declined since the Commission adopted the EDR in 2013, nine of the 10 counties in California with the highest unemployment rates as of December 2017 are entirely or partially in PG&E's service territory. These are mostly in the Central Valley. EDR may therefore continue to help retain employment in these areas by lowering electricity costs for some businesses.

26. The EDR settlement's proposed reduction in the maximum EDR discount from 30% to 25% results in less impact on businesses competing with EDR participants.

27. The proposed third-party auditing requirements for large EDR participants will help ensure attainment of energy efficiency, employment retention, and other public interest goals.

28. The proposed cap on EDR participation, as well as the prohibition on EDR renewal for participants, ensures that the settlement will not result in disproportionate rate impacts on non-EDR customers.

29. The expiration of EDR on December 31, 2020, or the final decision in PG&E's next GRC Phase II, whichever is later, will allow the Commission to revisit EDR in the near future and determine if it should continue.

30. There is no law prohibiting the existence of PG&E's EDR.

31. PG&E testified that EDR MW allocations may not be reused once an EDR agreement with a customer expires at the end of five years. However, the EDR settlement and EDR tariff attached to the settlement do not mention this prohibition.

32. The EDR settlement proposes to allow a customer with A-1 and A-6 meters to aggregate with an A-10 meter used by the same customer to establish that customer's eligibility for EDR. These meters, according to PG&E's testimony, must be located in the same "physical contiguous space." This term was not clearly defined during examination, and PG&E testified that meters "directly across the street" would "probably" qualify for EDR aggregation. The proposed EDR tariff attached to the EDR settlement uses an entirely different term, "a single Premises, as defined in PG&E's tariffs," to define the physical envelope in which the aggregated meters must be located.

33. Changes to electric baseline quantities for residential customers generally are justified given the change in PG&E's summer season from May-October to June-September.

34. The baseline quantities were calculated using average usage data for regular and all-electric customers, and the settling parties' determination that 53.8% of average usage should be used to set baseline quantities of average usage is near the middle of the range authorized by statute (i.e., 50% - 60%).

35. The determination of the parties to the residential settlement that 63.8% of average winter usage of all-electric customers should be used to set winter baseline quantities for all-electric customers is near the middle of the range authorized by statute (i.e., 60% - 70%).

36. Data provided by PG&E showed that increasing baseline quantities dramatically may have the unintended consequence of raising the price of baseline electricity, and increasing the bills of low-usage customers.

37. Changes to Territory Q's boundaries and baseline quantities are justified given the climatic characteristics of the San Lorenzo Valley.

38. Changes to the medical baseline outreach process will enhance public understanding and uptake of the program.

39. Replacing the current customer enrollment limitation for the EV rate schedule with a usage limitation will help to facilitate wide-scale EV adoption in PG&E's territory, which aligns with broader state policy goals.

40. Modification of the EV rate's peak and off-peak periods will better align peak rates with peak marginal generation costs.

41. PG&E's residential customers in the Central Valley experience greater levels of electric burden, on average, than other PG&E customers. The record of this proceeding also reflects that affordability, bill volatility, and disconnection concerns for PG&E's residential customers were most pronounced in the Central Valley. Yet the Residential Rate Design settlement does not directly

acknowledge these problems for PG&E residential customers generally or how acutely they are felt in the Central Valley.

42. Families whose household income slightly exceeds the CARE threshold will qualify to receive FERA discounts - a 12% discount on their electricity bill. PG&E's testimony reveals that the FERA program, through lack of outreach or for other reasons, is not very highly subscribed. PG&&E's subscription rate for the CARE program is far higher, and well above 50%.

43. If the Residential Rate Design settlement's methodology for determining whether a storage customer was eligible to take service on the EVA rate was literally applied it could deny residential customers with less than 12 months of consumption history the ability to take service on the EVA rate if they install energy storage. This could be a particular complication for customers that build and occupy new ZNE homes.

44. Delaying the mandatory conversion of medium and large customers to new peak periods will give PG&E time to fully educate these customers about the peak period changes and strategies for reducing energy consumption during peak periods.

45. The MLLP settlement proposes to collect between 70% and 100% of non-customer access-related distribution revenue for MLLP customers through non-coincident demand charges.

46. Exhibits CPUC-2 and PG&E-9 evidence how PG&E's distribution system as a whole tends to experience peak demands during the 4 p.m. to 9 p.m. period during the summer. Regardless of whether the individual load of a new business customer dictates the capacity of a single new business primary distribution capacity investment, the sum of those investments across PG&E's territory will tend to peak between 4 p.m. and 9 p.m. during the summer.

47. PG&E's witnesses testifying on behalf of the MLLP settlement also indicated that, upon examination of the evidence in CPUC-2 that most PG&E distribution circuits peak between 4 p.m. and 9 p.m., they could not distinguish between circuits that received different primary distribution capacity-related investments when assessing the distribution of circuit peaks.

48. NBPDCC are indisputably marginal costs that, as revealed through the record of this proceeding, are as likely to be spent on circuits that peak during the 4 p.m. to 9 p.m. peak period as any other marginal distribution investment made by PG&E.

49. The revisions we propose to the MLLP distribution demand charges still allow PG&E to collect the majority of their distribution demand charge revenue through non-coincident demand charges. We therefore find that these adjustments align more with the utility's perspective in this proceeding than in the recent SDG&E GRC Phase II proceeding where we allowed SDG&E to only collect approximately 39% of its distribution demand charge revenue through non-coincident demand charges.

50. We find that SDG&E's practice of identifying a separate marginal cost component for its substations improves the accuracy of marginal distribution capacity cost estimates.

51. No party other than PG&E proposed rates for A-10, and the settlement A-10 distribution rates are identical to the rates originally proposed by PG&E.

52. A-10 customers (other than solar and storage customers) were not actively represented by the settling parties, and the MLLP settlement A-10 rates were not based on a compromise among the various parties but, at least for distribution rates, simply reflected PG&E's opening position.

53. The agricultural rates settlement significantly simplifies the rate schedules available to agricultural customers and includes specific provisions for customer outreach and education on the new TOU periods.

54. The agricultural rates settlement delays implementation of the new TOU periods to March 2020 and 2021 to account for the seasonal nature of agricultural operations and allow for post-harvest education on the new TOU periods and rates before the commencement of summer season rates.

55. Mitigation measures for those agricultural customers most affected by the agricultural rates settlement's new TOU rates will be considered in PG&E's 2019 RDW proceeding.

56. If mitigation measures are not developed in time for the mandatory implementation of new TOU rates in March 2021, the most affected agricultural customers will be allowed to stay on legacy TOU periods and rates, as defined by the Agricultural TOU settlement, until March 2022.

57. The agricultural rates settlement includes a rate option for agricultural customers that allows for two days per week of off-peak usage to accord with agricultural operational needs.

58. The legacy solar TOU settlements generally seek to levelize the peak to part-peak prices as experienced by legacy TOU customers, in compliance with the principles of D.17-01-006. For those customers on rate schedules with high concentrations of legacy TOU customers – A-6, E-19R, E-20R – the levelization takes place over several years to allow for a transition to new peak period and peak to off-peak price ratios.

59. The legacy solar TOU settlements represent an effort by many parties to this proceeding, including consumer and renewable energy development advocates, to craft a transition in TOU peak periods and rates that allows for

customers with renewable energy systems to recoup a reasonable amount of their investment.

60. The streetlight rates settlement's proposed facility charges, customer charges, and energy charges are very similar to the current streetlight charges.

61. The Option S rate will assist customer-sited energy storage systems to produce ratepayer benefits by avoiding marginal utility costs and reducing GHG emissions.

62. An analysis of the data in CALSSA-2 indicates that the time period of 9 a.m. to 2 p.m. each day is when the marginal GHG emissions of the grid are generally at their lowest, and therefore this time period is appropriate for the "demand charge holiday" implicitly proposed by the SEIA's Option S proposal. This also corresponds to the "super off-peak" period adopted by PG&E and the MLLP settling parties for the months of March, April, and May, although under Option S this period of time free of demand charges will last all year.

63. The creation of a daily peak distribution demand charge, working alongside the other features of the Option S rate, will likely create incentives for energy storage that maximize the system benefits that can be provided by such technology by creating a daily incentive to reduce customer demand during peak hours (i.e., the rate will maximize discharge of the energy storage system during peak system hours every day of the month).

64. The SGIP GHG working group is not chartered to consider changes to rate design, and therefore cannot be relied upon to address this issue with as much efficacy as Option S.

65. In its application, PG&E proposes to calculate the master meter discount consistent with the methodology we adopted in D.11-12-053. That decision allowed PG&E to 1) include replacement costs through application of the RECC

to new equipment connection costs, 2) exclude any EPMC factors, 3) consider new connection costs to properly be the costs as capped by PG&E's line extension allowances under Rules 15 and 16 with application of the "rental method," and 4) use PG&E's multi-family residential costs as a reasonable proxy for the average avoided costs to otherwise directly serve tenants in master meter MHPs. For the DBA, PG&E proposes to use the same database and analytical methods used in its prior two GRC Phase II proceedings. The main difference in this proceeding is that the DBA analysis now accounts for the minimum bill that very low-usage residential customers are charged.

66. There are essential differences in the way in which RES-BCT customers and non-RES-BCT customers receive financial incentives through rates to install and operate renewable energy systems.

67. The sales forecasting mechanism for the agricultural class is flawed.

Conclusions of Law

1. While our policy is to favor the settlement of disputes, our standard of review for settlements is designed to ensure that settlements meet some minimum standard of reasonableness in light of the law and the record of the proceeding.

2. A settlement can be unreasonable, and we will not be persuaded to approve unreasonable settlements simply because of a general, long-standing policy to approve settlements.

3. There are several attributes that can render a settlement unreasonable. One such attribute is the presence of significant deviations from Commission findings, policies, practices that are not adequately explained and justified in the motion for the settlement's adoption. Another such attribute is the lack of a

demonstration that the settlement fully and fairly considered the interests of all affected entities – both parties and non-party entities such as affected customers.

4. We are under no duty to approve unreasonable settlements.

5. The findings and conclusions of D.96-04-050 remain valid and should be regarded as the starting point for the Commission's evaluation of whether revenue allocation and rate designs are reasonable.

6. EPMC based rate design is cost-based, a reasonable balance between equity and efficiency in revenue allocation and ratesetting, and the Commission's preferred starting point for evaluating the reasonableness of revenue allocation and rate design.

7. In our evaluation of whether PG&E's proposed revenue allocation and rate designs are reasonable, and therefore whether the settlements on these issues are reasonable, we should use EPMC as a starting point.

8. Other considerations may lead us to find that deviations from EPMC-based and marginal cost-based revenue allocation rate designs are reasonable, as we do in this proceeding.

9. In the revenue allocation context, "caps and floors" may be used to limit the rate impact of changes to a class's revenue allocation from one GRC Phase II proceeding to the next.

10. In the rate design context, fully cost-based rates may be mitigated in order to ensure that bill impacts between GRC Phase II cycles are not extreme.

11. Because revenue allocation has a direct impact on the rates faced by customers the Commission is obligated to consider whether the revenue allocation assigned to each of PG&E's 20 customer classes leads to just and reasonable rates.

12. We find that the marginal cost proposals of PG&E, as modified by the MC/RA settlement, are reasonable in spite of the fact that the settling parties did not actually agree on particular marginal cost values for each class.

13. PG&E's revenue allocation and marginal cost proposals, as modified by the MC/RA settlement, are reasonable and should be adopted.

14. We do not accept the MC/RA settlement's proposal that the separate "tree mortality program" NBC under development in A.16-11-005 will be calculated as a separate charge and added to PPP rates. The matter of how to charge the tree mortality NBC remains open until resolved in A.16-11-005.

15. PG&E's proposed revenue requirement increase of approximately $510,000 for recovery of certain costs incurred to develop a real time pricing proposal is reasonable and should be adopted, as the recovery of these costs were sought through a rate design proceeding as ordered by D.08-07-045, and none of the parties to the MC/RA settlement objected to the recovery of these costs.

16. PG&E's proposal to reallocate SGIP related revenue among the classes on an annual basis pursuant to Resolution E-4926, rather than a triennial basis, is reasonable and should be adopted.

17. PG&E complied with the principles outlined in D.17-01-006 by using marginal generation costs, as represented by adjusted net load, and distribution contributions to peak demand to determine appropriate TOU seasons and periods.

18. In light of the testimony provided by PG&E and the unanimous support for the seasonal definition in the settlements, we find that a summer season of June – September for PG&E's TOU customers is reasonable in light of the whole record, consistent with law, and in the public interest.

19. Revisions to the TOU period definitions utilized by California's electric utilities are necessary and in the public interest given the current conditions faced by California's electricity grid.

20. As the proposed PG&E peak summer TOU period of 4 p.m. to 9 p.m. aligns with that approved for SDG&E in D.17-08-030, utilizes data recommended by D.17-01-006, and is generally reflective of the highest marginal cost hours experienced by PG&E, it comports with our current position on an appropriate peak period definition and should be approved.

21. Particular operational needs of agricultural customers justify an earlier end to the peak period than for non-agricultural customers.

22. In light of the settlement negotiations, the good faith efforts of the parties to resolve issues, and our previous findings with respect to TOU period modifications in previous decisions, we find that the new TOU periods as defined by the various settlements in this proceeding are reasonable in light of the whole record, consistent with law, and in the public interest.

23. While the EPMC methodology is an appropriate starting point for rate design, there are other principles that influence our determination of whether a given rate design is reasonable, and therefore whether a given settlement on rate design issues is reasonable. These other rate design principles are as follows:

- Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost;
- Rates should be based on marginal cost;
- Rates should be based on cost-causation principles;
- Rates should encourage conservation and energy efficiency;
- Rates should encourage reduction of both coincident and non-coincident peak demand;

- Rates should be stable and understandable and provide stability, simplicity and customer choice;
- Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals;
- Incentives should be explicit and transparent;
- Rates should encourage economically efficient decision-making; and
- Transitions to the new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

24. Various Commission decisions in the last several years have memorialized our commitment to TOU rates in general as a cost-based form of rate design that can enhance bill savings for those customers that shift usage to off-peak periods and reduce utility expenditures on marginal investments.

25. It is Commission policy that TOU rates in general are reasonable and should be adopted for PG&E's customers.

26. PG&E's originally proposed rate designs and certain settlement rate designs did not adequately consider EPMC or marginal cost responsibility.

27. The revenues collected through the proposed peak and part-peak demand charges should either reflect the current revenue collected to account for marginal costs, or a new winter peak demand charge should have been created to account for the 2-month reduction in the summer period.

28. PG&E's proposed substantial increases to its non-coincident demand charges at the expense of its coincident demand charges do not comply with state policies seeking to incent socially beneficially electricity usage.

29. PG&E's proposed rate designs in this proceeding do not comply with the recommendation of D.17-01-006 for utilities to provide a menu of different TOU rate options within classes, with enhanced marginal cost signals.

30. PG&E's general rate design approach for its non-residential TOU customers, as expressed in the various settlements to this proceeding, whereby it increases non-coincident demand charges at the expense of peak-related demand charges, and flattens price differentials between peak and off-peak volumetric prices, runs counter to California's broad energy policy goals as well as the direction taken by the Commission in D.17-08-030, D.17-01-006, and other decisions.

31. While we approve most of the settlements on PG&E's rate designs in this proceeding, we wish to state clearly that we approve them in spite of the considerable backsliding away from cost-based rates that the proposals represent.

32. Although reflection of cost-causation may be muted when new TOU rates are initially being introduced, over time each rate design should be able to reflect the cost to serve enrolled customers with increasing accuracy.

33. Given that fully-scaled EPMC rates have been, and remain, the Commission's standard for cost-based, fair, and equitable non-residential rates, we find that applying this standard does not result in cost-shifting.

34. Failure to scale time-dependent marginal costs in peak energy charges and peak demand charges shifts costs to other rate components, in particular off-peak energy charges and non-coincident demand charges. Customers appropriately shifting usage to off-peak hours would therefore pay more for utility service than they should given the costs incurred to serve them.

35. The circumstances of D.11-05-047 cited by PG&E in PG&E-39 do not apply in a non-residential context, and nothing in D.11-05-047 leads us to alter our broad conclusions about the use of EPMC for both revenue allocation and cost-based rate design.

36. The back-and-forth between the parties to the SLP settlement resulted in a reasonable outcome that does not produce unjust or unreasonable rates. Increases to customer charges such as those proposed by the SLP settlement were also accepted under previous Commission decisions, including D.17-08-030 where customer charges for some classes were authorized to increase by 20% a year. We therefore find that the SLP settlement's proposed changes to the customer charges are reasonable in light of the whole record, consistent with law, and in the public interest.

37. The SLP settlement on A-1 TOU energy charges and structure is reasonable in light of the whole record, consistent with law, and in the public interest.

38. There is a public interest in creating differentials between peak and off-peak pricing throughout the year that may help incent energy storage operation that leads to reductions in GHG emissions.

39. The SLP settlement appears to represent a reasonable compromise on the proposed A-1 STORE rate, and we find that the A-1 STORE rate is reasonable in light of the whole record, consistent with law, and in the public interest.

40. It is important not to tie the eligibility for the A-1 STORE rate to SGIP eligibility as SGIP is due to retire on January 1, 2020. Eligibility for the A-1 STORE rate must outlive SGIP's planned retirement.

41. Because there is very little record analyzing the proposed A-6 rate structure, the rate structure was included as part of an arm's-length settlement reached with parties representing the interests of this class of ratepayer, and

because we presume that the flattened A-6 price differentials are intended to promote customer acceptance of new TOU periods, we find that the SLP settlement's proposed A-6 rate structure is reasonable in light of the whole record, consistent with law, and in the public interest.

42. The changes made to the A-6 rate by the SLP settlement exemplify how the rate design principles used by PG&E in this proceeding diverge from our previous decisions and state policy.

43. Given that there was substantial give-and-take between the settling parties during arm-length negotiation on these items, the other elements of the SLP settlement are approved as reasonable in light of the whole record, consistent with law, and in the public interest.

44. The proposed modifications allowing smaller businesses to participate in the EDR creates a more equitable program.

45. The EDR settlement is reasonable in light of the whole record, consistent with law, and in the public interest.

46. PG&E's proposed baseline quantity calculations in the residential settlement comply with the requirements of SB 711.

47. The Residential Rate Design settlement is reasonable in light of the whole record, consistent with law, and in the public interest.

48. Affordability issues for residential customers were not addressed by the Residential Rate Design settlement in any meaningful way. While the affordability of residential electricity is a key public policy goal, the residential settlement was nearly silent on this issue.

49. While R.12-06-013 is the main forum to discuss residential rate design issues statewide, each investor-owned utility should acknowledge the

importance of the residential affordability issue in their individual rate design proceedings and propose steps to address it.

50. As it is justified for the residents of the San Lorenzo Valley to receive a baseline allowance that aligns with the allowance enjoyed by other PG&E residential customers in areas with similar climatic conditions, fairness requires that all of PG&E's residential customers should receive the benefit of baseline quantities that reflect the climatic conditions of their location.

51. Ultimately, PG&E should achieve a similar subscription level for FERA as for CARE.

52. It is necessary to determine what an essential amount of electricity is for PG&E residential customers, including those households in the Central Valley, instead of relying on the proxy of baseline quantities. This type of information would be instrumental so that PG&E, stakeholders and the Commission can better evaluate whether PG&E's residential customers are meeting their basic electricity needs at a reasonable cost.

53. In light of the comments made by the parties on this issue, we find that adjusting baseline quantities is not the best way to make efforts to address residential bill volatility at this time, given that the impacts are expected to be small and that the price of baseline energy would be increased as a result. The record demonstrates that there are other mechanisms that can, and should, be used to address bill volatility that would not have the effect of increasing the price of baseline energy.

54. The generation demand charges, energy charges and customer charges for each rate schedule proposed by the medium and large light and power (MLLP) settlement are reasonable in light of the adjustments customers will need to make to the new TOU peak periods.

55. The MLLP settlement's proposed Food Bank Rate is reasonable and in compliance with the law.

56. Consistent with our standard of review for uncontested settlements, we find that the MLLP settlement's distribution demand charge rate design is unreasonable in light of the whole record, the law, and the public interest. The MLLP settlement's distribution demand charge rate design is also not in accord with previous Commission decisions, including the decision in the recent SDG&E GRC Phase II proceeding (D.17-08-030).

57. Because the MLLP settlement establishes rates for PG&E's most sophisticated customers that can respond quickly to rate signals, the countervailing concern of customer acceptance of new TOU periods does not apply as forcefully here as it does with respect to the other settlements. In light of the reduced need to promote customer acceptance of new TOU periods for these customers, we find that the MLLP settlement's distribution demand charge rate design is unreasonable as it does not adequately promote the public interest.

58. Heavy reliance on non-coincident demand charges is generally disfavored by our historic rate design principles because non-coincident demand charges do not reflect cost causation for primary distribution, transmission, or generation capacity costs.

59. Rate designs that heavily rely on non-coincident demand charges also promote inefficient use of energy contrary to state policy goals encouraging economically efficient and socially beneficial energy usage. Therefore, the proposal by PG&E and the MLLP settlement to collect between 70% and 100% of non-customer access-related distribution revenue for MLLP customers through non-coincident demand charges is unreasonable in light of our historic rate design principles.

60. The objective of using marginal distribution costs and timing of distribution system peaks in determining base TOU periods is to better align time-differentiated rates with time-differentiated marginal costs. It would therefore be illogical to create a TOU peak period based on marginal costs and then not assign time-based marginal cost recovery to those peak periods.

61. To be consistent with our rate design principles and previous Commission decisions, actual distribution capacity-related marginal costs (excluding marginal customer access costs) attributable to MLLP customers should be reflected in peak and part-peak distribution rates experienced by those customers. To find otherwise would not be reasonable in light of the whole record of this proceeding, our rate design principles, or previous Commission decisions.

62. The MLLP settlement strays too far from marginal cost-based ratemaking principles by excluding recovery of NBPDCC in time-based distribution charges.

63. The agricultural rates settlement is reasonable in light of the whole record, consistent with law, and in the public interest.

64. Significant reductions in price differentials between peak and off-peak periods and the lack of time-differentiation for distribution charges on any of the default agricultural rates in the agricultural rates settlement is not in accord with Commission policy and previous decisions.

65. The legacy solar TOU settlements' treatment of legacy solar customers complies with the mandates and guidelines of D.17-01-006 and other applicable law.

66. A gradual lowering of the generation differential between the peak and part-peak periods over several years for A-6, E-19R, and E-20R legacy solar customers is appropriate given the high concentration of legacy TOU customers on those rates.

67. The legacy solar TOU settlements are reasonable in light of the whole record, consistent with law, and in the public interest.

68. The streetlight rates settlement's proposed changes to the streetlight charges are reasonable in light of the whole record, consistent with law, and in the public interest.

69. The continuation of the Network Controlled Dimmable Streetlight Pilot Program is warranted and reasonable.

70. A fully automated dimmable streetlight system for streetlight customers is in the public interest and should be pursued expeditiously.

71. As the petition to modify D.18-01-013 demonstrates that all of the original parties to the DA/CCA settlement agree to the modifications proposed by the petition, the petition is approved.

72. The Option S rate is generally consistent with PG&E's efforts in the residential rate design and small commercial rate design settlements to create limited, opt-in rates for energy storage customers that will lead those customers to avoid utility costs and reduce emissions of GHGs.

73. PG&E's definition of "non-coincident" distribution costs to be collected through non-coincident distribution demand charges for MLLP customers is flawed.

74. Adoption of the Option S proposal will help PG&E meet the principle of D.17-01-006 that a menu of rate design options should be offered for different kinds of customers, including those that install energy storage technology.

75. Because daily demand charges have yet to be tested at the scale proposed by Option S in California, it is important that we study the experience with Option S rates to determine if they optimize the behavior of customer-sited energy storage systems.

76. In order to calculate the master meter discount in compliance with Public Utilities Code Section 739.5(a), we must estimate 1) the avoided costs that PG&E would have incurred in providing submeter service; 2) the estimated line losses to compensate a master meter customer for the electricity that is ordinarily lost when it is transmitted across the master meter customer's distribution network; and 3) the DBA which reduces the master meter discount paid to the owner of a mobile home park to account for the fact that while the master meter operator receives a full baseline allowance for each tenant space, some tenants use less than the baseline allowance and some tenant spaces may be vacant.

77. The methodology for calculating the master meter discount was used in the last Commission decision to consider these issues in depth – D.11-12-053 – and we adopt it in this decision as well.

78. PG&E's proposed methodology for calculating the master meter discount is consistent with the methodology for calculating the master meter discount as adopted in D.11-12-053. While a party to the proceeding advanced several arguments for why a different methodology should be used, and why PG&E's proposed methodology does not comply with the requirements of Public Utilities Code Section 739.5(a), we reject those arguments. We hold in this decision that PG&E's proposed methodology complies with D.11-12-053 and Public Utilities Code Section 739.5(a), and consequently base our calculation of the master meter discount on PG&E's proposed methodology.

79. Consistent with principles of equity and the overall policy of the state of California to support customer-sited renewable energy development, the legacy solar TOU settlement must treat RES-BCT customers in such a way as to create equal treatment with respect to the reduced financial incentives to install and operate customer-sited renewable energy systems.

80. While it is appropriate to apply the terms of the legacy solar TOU settlement to RES-BCT customers, those terms must ensure equal treatment between NEM and RES-BCT customers with respect to their diminished returns for the generation of renewable energy.

81. The sales forecasting mechanism for the agricultural class should be refined such that the forecasts are more accurate.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) shall implement revenue allocation resulting from the Marginal Cost / Revenue Allocation settlement as soon as practicable following the issuance of this decision. The revenue allocation will apply to any future changes in PG&E's rates until the decision in the next PG&E General Rate Case Phase II proceeding is issued.

2. Pacific Gas and Electric Company shall implement the revised summer season as soon as practicable following the issuance of a final California Public Utilities Commission decision in this proceeding.

3. Pacific Gas and Electric Company (PG&E) shall refresh its data appearing in Chapter 12 of PG&E-9 for its next General Rate Case Phase II application and describe why June should or should not be included in its summer season in that application. PG&E shall also include illustrative rate impacts that would result from 1) a shortening of PG&E's summer season to July – September for all of its customer classes on seasonal rates, and 2) a revision of the summer season to July – October for all of its customer classes on seasonal rates.

4. Pacific Gas and Electric Company shall implement the revised Time-of-Use periods appearing in the various settlements in this proceeding as soon as practicable following the issuance of a final Commission decision in this proceeding.

5. Pacific Gas and Electric Company (PG&E) shall propose more cost-based rates, based on full equal percent of marginal cost (EPMC) scaling of all marginal cost components, for its non-residential Time-of-Use (TOU) customers in next General Rate Case Phase II proceeding. PG&E shall also propose an alternative set of rates that, while not based on full EPMC scaling, are more cost-based than those approved by this decision. PG&E must also propose a menu of TOU options for all of its non-residential TOU customers, not simply its storage customers, such that those customers that believe they can respond to fully scaled marginal cost-based rates are able to do so.

6. Pacific Gas and Electric Company shall file a transmission cost causation study with its next General Rate Case Phase II application. This study must examine the appropriate allocation of transmission costs between non-coincident demand charges and system peak demand charges.

7. Pacific Gas and Electric Company shall implement the revised small light and power customer charges as soon as practicable following the issuance of a final Commission decision in this proceeding.

8. Pacific Gas and Electric Company (PG&E) shall implement the revised A-1 Time-of-Use rate as soon as practicable following the issuance of a final Commission decision in this proceeding. PG&E shall specify eligibility criteria for A-1 STORE rate participation that do not simply cross-reference to the Self-Generation Incentive Program (SGIP) Handbook or other SGIP rules. The eligibility criteria must be set out in the tariff sheet and stand on their own.

PG&E must also clarify that the non-coincident demand charge as proposed for the A-1 STORE rate only applies between the hours of 2 p.m. and 11 p.m.

9. Pacific Gas and Electric Company (PG&E) shall implement the revised A-6 rate as soon as practicable following the issuance of a final Commission decision in this proceeding. PG&E must propose a more cost-based rate for A-6 customers in its next General Rate Case Phase II application, and include an optional rate for A-6 customers that uses an enhanced marginal cost signal.

10. Pacific Gas and Electric Company shall implement the elements of the small light and power settlement as described in Section 6.3.5 as soon as practicable following the issuance of a final Commission decision in this proceeding.

11. Pacific Gas and Electric Company (PG&E) shall implement the elements of the economic development rate (EDR) settlement as soon as practicable following the issuance of a final Commission decision in this proceeding. However, PG&E shall modify its EDR tariff to clarify that once a certain amount of megawatts (MW) in its EDR cap is used for a five year agreement, and that agreement naturally terminates at the end of five years, those MW must be retired and may not be used to support other EDR applications. PG&E must track those EDR MW retirements and report on the total number of retired EDR MW in its next General Rate Case Phase II application. PG&E shall clearly define in the EDR tariff sheet the physical envelope in which the aggregated EDR meters must be located. This definition must be detailed enough to allow a layperson to understand if their meters fall within the envelope or not. Cross-references to other portions of PG&E's tariffs are not acceptable.

12. Pacific Gas and Electric Company shall continue to file the annual Economic Development Rate (EDR) program performance reports adopted in

Decision 13-10-019, and they must now include reporting on the third-party auditing outcomes described in the EDR settlement.

13. Pacific Gas and Electric Company (PG&E) shall implement the terms of the Residential Rate Design settlement as soon as practicable following the issuance of a final Commission decision in this proceeding, except that PG&E must allow those residential storage customers with less than 12 months of consumption data to participate in the Schedule EV-A opt-in program. In lieu of estimating the customer's future usage, we set the minimum size of the installed energy storage system for those customers with less than 12 months of consumption data to be 2 kilowatt-hours.

14. Pacific Gas and Electric Company (PG&E) shall develop a model of what constitutes essential electricity use for its residential customers. This model must be developed using research, both existing (information sources such as the Residential Appliance Saturation Survey and Experian data) and new direct customer surveys, to collect information on household size (in terms of both square footage and number of residents), building features (age, construction materials, insulation, etc.), and appliances (efficiency and usage) in order to better evaluate the essential electricity needs of PG&E's residential customers. This model of essential usage must be able to specify the amount of essential usage in both summer and winter for residential customers separately in each of the hot climate zone (baseline territories R, S, W, and P), the warm climate zone (baseline territories X and Y), and the cool climate zone (baseline territories T, V, and Z). Separate analysis of Territory Q is unnecessary at this time. This model and its results must be submitted with PG&E's next General Rate Case Phase II application. PG&E shall consult with parties to this proceeding, if a party expresses interest, when developing this research and model..

15. Pacific Gas and Electric Company (PG&E) shall make significant efforts to achieve a Family Electric Rate Assistance (FERA) subscription level of at least 50% before its next General Rate Case Phase II filing. PG&E should particularly focus its efforts in the Central Valley, as suggested by PG&E and other parties to the residential rate design settlement. PG&E should work with community-based organizations (CBOs) in the Central Valley to increase rates of FERA participation. PG&E should hold one or more workshops in the Central Valley in 2018 with local CBOs toward this effort. PG&E shall report to Energy Division by December 31, 2018 and December 31, 2019 on its progress to increase FERA subscription.

16. In order to provide the Commission with the opportunity to consider new ways of defining baseline territories that prioritize simplicity and fairness for customers, Pacific Gas and Electric Company (PG&E) must propose revisions to its electric baseline territory boundaries and allowances in its next General Rate Case Phase II application, as described in Ordering Paragraphs 17, 18, and 19.

17. Pacific Gas and Electric Company (PG&E) must analyze the climatic records of each National Oceanic and Atmospheric Administration – National Weather Service (NWS) station with 30-year average summer maximum temperature and winter minimum temperature within its territory. PG&E must then determine if residential customers in the vicinity of each weather station receive appropriate amounts of baseline electricity allocations given the climatic conditions experienced by each group of customers. PG&E shall determine this appropriateness by comparing the climatic condition of the customers (as revealed by the NWS weather station data) to the average climatic condition of the baseline territory in which the customers are located and all other existing PG&E baseline territories. If PG&E finds that the climatic conditions of the

customers are a better match for a different baseline territory than their current territory, then PG&E must assign that group of customers to the baseline territory that is a better match. PG&E must conduct this analysis separately for winter and summer climatic conditions, and match each group of customers with its best fit for each season, even if that results in different baseline territories for each season. PG&E shall ensure that all of its residential customers are afforded the same consideration granted to customers in the San Lorenzo Valley in this proceeding.

18. Pacific Gas and Electric Company (PG&E) must also provide a simplified baseline territory system for our consideration whereby the number of summer and winter baseline territories in PG&E territory is limited to no more than three for each season. Each territory created shall be based on climatic conditions with specifically described characteristics of PG&E's choice (e.g., average summer maximum temperatures above 90 degrees). PG&E shall then assign its residential customers to the new territories depending on their local climatic conditions (as revealed by NWS weather station data).

19. Pacific Gas and Electric Company must calculate new electric baseline allowances under each of these revisions as spelled out in Ordering Paragraphs 17 and 18 and submit them with its next General Rate Case Phase II application. Maps showing the results of the revisions must also be submitted.

20. Pacific Gas and Electric Company must provide usage alerts to Schedule EV customers similar to those provided to High Usage Surcharge customers so that they are aware of the risk of being transferred to Schedule E-TOU-B.

21. Pacific Gas and Electric Company shall identify marginal substation capacity costs as a separate component of its marginal distribution capacity costs in its next General Rate Case Phase II application.

22. Pacific Gas and Electric Company (PG&E) must propose rates for the A-10 class in its next General Rate Case (GRC) Phase II proceeding that more closely hew to cost-causation than the rates approved in this decision. PG&E must demonstrate in their ultimate rate proposal for A-10 customers in their next GRC Phase II proceeding (whether through settlement or litigated position), that the interests of A-10 customers were represented in an arms-length fashion in the development of new A-10 rates.

23. Pacific Gas and Electric Company shall implement the terms of the agricultural rates settlement as soon as practicable following the issuance of a final Commission decision in this proceeding.

24. Pacific Gas and Electric Company must propose in its next General Rate Case Phase II application agricultural rates (along with all other non-residential Time-of-Use rates) that better reflect time-differentiation of marginal distribution costs, and contain peak-to-off-peak price differentials that encourage agricultural customers to invest in energy management technology and practices that allow them to respond to peak price signals.

25. Pacific Gas and Electric Company shall implement the terms of the legacy solar Time-of-Use settlements as soon as practicable following the issuance of a final Commission decision in this proceeding.

26. Pacific Gas and Electric Company must make a proposal for a fully automated dimmable streetlight billing system and a rate design to give effect to it in its next General Rate Case Phase II application.

27. Pacific Gas and Electric Company shall implement the streetlight rate design settlement as soon as practicable following the issuance of a final Commission decision in this proceeding.

28. Pacific Gas and Electric Company shall file an advice letter making proposed changes to Electric Rules 22 and 23, as outlined in the petition to modify Decision 18-01-013, no later than 30 days after the issuance of this decision.

29. Pacific Gas and Electric Company (PG&E) must create an Option S rate for A-10, E-19, and E-20 customers with the following characteristics: PG&E must use the same technology eligibility language as it uses for the A-1 STORE rate. An eligible energy storage system must have a rated capacity in watts which is at least 10% of the customer's peak demand over the previous 12 months. The Option S tariff sheet shall include a method for calculating rated capacity that mirrors the existing calculation from the Self-Generation Incentive Program Handbook. PG&E shall begin the design of the Option S rate by making it identical to the Option R rate available to the customer. For A-10 customers that do not have an Option R rate available, PG&E must construct an Option R rate for those customers that mirrors the rules for Option R customers on E-19 and E-20, with the addition of daily distribution demand charges as described below. After duplicating the Option R rate design, 80% of the revenue that would otherwise be collected from an Option R A-10, E-19, or E-20 customers by non-coincident distribution demand charges shall be collected instead through daily demand charges assessed during the peak period only (4 p.m. to 9 p.m. for medium and large light and power customers) for customers on Option S. After duplicating the Option R rate design, 20% of the revenue that would otherwise be collected from Option R A-10, E-19, or E-20 customers by non-coincident

distribution demand charges shall be collected through a non-coincident distribution demand charge for customers on Option S, except that no distribution demand charges may be assessed between 9 a.m. and 2 p.m. each day. Option S shall collect all distribution demand charge revenue through daily demand charges for participating A-10, E-19, and E-20 customers. In other words, all existing Option R monthly peak demand charges shall be converted to daily peak distribution demand charges for Option S customers. And all existing Option R monthly part-peak demand charges shall be converted to daily part-peak distribution demand charges for Option S customers. The daily demand charge price for Option S customers shall not vary throughout a given month (i.e., it must be a constant $/kilowatt/day during the month).

30. Pacific Gas and Electric Company shall cap enrollment in Option S at 324 megawatts (MW) of installed energy storage rated capacity, with 108 MW portions of this total assigned to each of the A-10, E-19, and E-20 customer groups.

31. Pacific Gas and Electric Company must make available the Option S rates at the earlier of 1) the same time that all other A-10, E-19, and E-20 rates as modified by the medium and large light and power settlement are available for opt-in enrollment, or 2) January 1, 2020.

32. Pacific Gas and Electric Company (PG&E) must study the performance of a representative sample of Option S energy storage systems after 12 months of operation, and compare them with the performance of a representative sample of non-Option S energy storage systems of comparable size on the relevant medium and large light and power rate (A-10, E-19, or E-20), to determine the impact of Option S rates on energy storage performance and any potential cost-shift that results from that performance. The cost-shift analysis must account for the

benefit of reduced peak usage and reduced greenhouse gas emissions as well as avoided payments for embedded costs. This study is due at the time of PG&E's first rate design application filed after January 1, 2021.

33. Pacific Gas and Electric Company (PG&E) shall calculate the base Schedule ET master meter discount at a level of $5.16/month/tenant space, in light of the estimates of PG&E's avoided costs for not serving submetered tenants of master meter customers. This figure shall be adjusted before final implementation to account for changes to PG&E's Real Economic Carrying Cost calculation that result from the Tax Cuts and Jobs Act, as requested by the Utility Reform Network.

34. Pacific Gas and Electric Company shall set the line loss adjustment for the master meter discount at a level of $2.18/month/tenant space.

35. Pacific Gas and Electric Company shall set the diversity benefit adjustment (DBA) for the master meter discount at a level of $5.37/month/tenant space to reflect the methodology for calculating the DBA used in prior decisions on this topic.

36. Pacific Gas and Electric Company shall calculate a Schedule ES master meter discount figure based on the Schedule ET discount using the methodology proposed in its testimony and briefs.

37. Pacific Gas and Electric Company must ensure that legacy A-6 Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) customers, as a class, experience no greater percentage annual decreases in their effective benefits than those received by legacy A-6 net energy metering (NEM) customers, as a class, for the same energy produced at the same time of day on the same otherwise applicable rate schedule. This does not mean that NEM legacy solar customers and RES-BCT legacy solar customers must receive the

same absolute amount of bill credit for each kilowatt-hour generated, but that the rate of decrease in that credit for the same energy produced at the same time of day on A-6 from year-to-year must be the same.

38. Pacific Gas and Electric Company shall propose an improved sales forecasting mechanism for the agricultural class in its next Energy Resource Recovery Account proceeding, and shall involve the agricultural parties to this proceeding in the development of that improved mechanism.

39. Application 16-06-013 is closed.

This order is effective today.

Dated ______________________________, at San Francisco, California.