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TO PARTIES OF RECORD IN APPLICATION 19-11-019:

This is the proposed decision of Administrative Law Judges Doherty and Sisto. 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 November 18, 2021 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 8.2(c)(4).

/s/ ANNE E. SIMON
Anne E. Simon
Chief Administrative Law Judge

AES:mph
Attachment

Decision **PROPOSED DECISION OF ALJs DOHERTY AND SISTO**
(Mailed 10/18/2021)

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 19-11-019

DECISION ADOPTING MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGNS FOR PACIFIC GAS AND ELECTRIC COMPANY

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Appendix A - Abbreviations, Acronyms, and Definitions

DECISION ADOPTING MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGNS FOR PACIFIC GAS AND ELECTRIC COMPANY

Summary

This decision adopts marginal costs for Pacific Gas and Electric Company (PG&E) to be used in the allocation of revenue among PG&E's customer classes and the design of retail rates for PG&E's customers. This decision largely adopts PG&E's proposed marginal costs and methodologies for deriving them but adopts marginal connection equipment costs proposed by the Agricultural Energy Consumers Association and marginal transmission capacity costs proposed by the Solar Energy Industries Association.

This decision also adopts, without modification, several uncontested settlements on rate design issues and revenue allocation. The proceeding will remain open to consider issues related to real-time pricing proposals for PG&E's customers.

1. Procedural History and Issues to be Determined

Pacific Gas and Electric Company (PG&E) filed this General Rate Case (GRC) Phase 2 application (Application (A.) 19-11-019) on November 22, 2019. California Farm Bureau Federation (CFBF) filed a protest to the application on January 9, 2020. Other protests were filed on January 10, 2020 by the Agricultural Energy Consumers Association (AECA), the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), the Joint Community Choice Aggregators (Joint CCAs),[1] the Joint Storage Parties,[2] and the

[1] Consisting of East Bay Community Energy, Peninsula Clean Energy, Marin Clean Energy, Pioneer Community Energy, San Jose Clean Energy, Silicon Valley Clean Energy, and Sonoma Clean Power.

[2] Consisting of OhmConnect Inc., California Solar & Storage Association, and the California Energy Storage Alliance.

Utility Reform Network (TURN). Responses to PG&E's application were filed on January 10, 2020 by Direct Access Customer Coalition (DACC), Small Business Utility Advocates (SBUA), Solar Energy Industries Association (SEIA), Center for Accessible Technology (CforAT), County of Santa Clara, Merced Irrigation District and Modesto Irrigation District, and Energy Producers and Users Coalition (EPUC). Federal Executive Agencies (FEA) was granted party status on January 22, 2020. Kern County Taxpayers Association was granted party status on February 6, 2020. California Manufacturers & Technology Association (CMTA) was granted party status on February 13, 2020. City and County of San Francisco was granted party status on May 8, 2020. Energy Users Forum (EUF) was granted party status on June 8, 2020. Natural Resources Defense Council (NRDC) was granted party status on July 8, 2020. Sierra Club was granted party status on August 6, 2020. Enel X North America, Inc. (ENELX) was granted party status on September 10, 2020.

A prehearing conference (PHC) was held on January 23, 2020. The following entities were granted party status at the PHC: the California Street Light Association (CALSLA), California Large Energy Consumers Association (CLECA), and the Western Manufactured Housing Communities Association (WMA).

The Assigned Commissioner's Scoping Memo and Ruling (scoping memo) was filed on February 10, 2020. The scoping memo created a second track of this proceeding for expedited consideration of an essential usage study (EUS) plan. A decision on that track of the proceeding (Decision (D.) 20-09-021) was issued on September 28, 2020. The remaining track of the proceeding was to consider the following issues:

1. Whether PG&E's proposed marginal electric costs and cost of service calculations are reasonable and should be approved.
2. Whether PG&E's proposed revenue allocation amongst its electric customer classes, including PG&E's proposal to move all its electric classes to full cost of service over a six-year period, is reasonable and should be approved.
3. Whether PG&E's proposed rate designs, including its demand charges, customer charges, dynamic rate options, and proposed time-of-use periods and seasons, are reasonable and should be approved.
4. Whether PG&E should implement a fully integrated Dimmable Streetlight Program, and if so the requirements and design of such a program, including the appropriate means of tracking and approving expenditures for such a program.
5. Whether PG&E's proposed residential baseline territory boundaries are reasonable and should be approved.
6. Whether PG&E's proposed gas and electric baseline quantities are reasonable and should be approved.
7. Whether PG&E's proposed revisions to its economic development rate program are reasonable and should be approved.
8. Whether PG&E's direct access and community choice aggregator fee revisions are reasonable and should be approved.

Public participation hearings were held virtually on November 6, 2020 at 2:00 pm and 6:00 pm. A transcript of those hearings is available on the docket card for this proceeding.

On August 27, 2020, the assigned Administrative Law Judge (ALJ) issued a ruling seeking party testimony on real-time pricing rate design issues for consideration in this proceeding. In November and December 2020, two motions were filed seeking to consolidate the real-time pricing rate design issues with a separate Commission proceeding considering a real-time pricing structure for certain PG&E electric vehicle charging station operators (A.20-10-011). Both motions were denied. However, several parties jointly filed a motion on January 27, 2021 seeking to bifurcate the real-time pricing rate design issues from the other marginal cost and rate design issues in this proceeding and consider them on a delayed track that would allow for complementary consideration of issues arising in A.20-10-011. This motion was granted on February 2, 2021.

The bifurcation of the real-time pricing issues required a revision to the proceeding schedule, and an Assigned Commissioner's Amended Scoping Memo and Ruling (amended scoping memo) was filed on February 16, 2021 to clarify the remaining procedural schedule.

PG&E served supplemental opening testimony on July 16, 2020. Cal Advocates served its opening testimony on October 23, 2020, and other intervenors served their opening testimony on November 20, 2020. Rebuttal testimony was served by all parties by February 26, 2021.

Several motions were filed seeking adoption of settlements in this proceeding. PG&E filed a motion to adopt a streetlight rate design settlement on February 23, 2021, a motion to adopt a residential rate design settlement on March 29, 2021, a motion to adopt a revenue allocation settlement on April 8, 2021, a motion to adopt an agricultural rate design settlement on April 8, 2021, a motion to adopt an economic development rate settlement on April 8, 2021, and a motion to adopt a commercial and industrial rate design settlement on April 13, 2021.

Evidentiary hearing was held on April 8, 9, 12, 13, 14, 16, 19, and 22, 2021. The parties filed opening briefs on May 20, 2021 and reply briefs on June 10, 2021. On June 16, 2021 the ALJ required PG&E to submit further evidence and PG&E served Exhibit PG&E-48 in response on July 16, 2021. PG&E served a revision to that response as Exhibit PG&E-49 on August 11, 2021, and upon that date this phase of the proceeding was considered submitted.

1. Marginal Cost-Based Ratemaking

This decision adopts and reinforces several holdings from the Commission decision in PG&E's prior GRC Phase 2 proceeding (D.18-08-013) related to the use of marginal costs to design rates.[3] Namely, this decision continues to hold that marginal cost-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."[4] The use of marginal costs is consistent with an economic approach to ratemaking that seeks to impose the greatest utility rates on those customers that impose the greatest costs on the utility at the margin (*i.e.*, the greatest costs imposed by requiring an additional unit of a given utility service). In this way, those customers that impose the greatest marginal costs have the most incentive to reduce their usage and demand, which in turn should drive down the utility's marginal expenses most efficiently. This reduction in utility expenses ultimately benefits all utility customers through lower overall rates.

Not only is this approach economically efficient and rational, it is also fair. As a matter of fairness, those customers and customer classes that are less expensive to serve should enjoy the benefit of that status, and those customers that cost more to serve should see that status reflected in their rates.

[3] D.18-08-013 at 13-20, referring to rates based on marginal costs as using the Equal Percent Marginal Cost method.

[4] D.18-08-013, Conclusion of Law (COL) 6.

This broad approach to ratemaking and revenue allocation is the backdrop for the Commission's consideration of PG&E's marginal costs in this decision. While true marginal cost-based rates and revenue allocation are ultimately not adopted by this decision due to the approval of an uncontested settlement on revenue allocation that significantly reduces the impact of marginal costs on rates, this principle is still the foundation of the Commission's approach to these issues.[5] In this context this decision proceeds with its analysis of the litigated marginal cost proposals.

2. Marginal Distribution Costs

Marginal distribution costs include the costs needed to provide customer connection to the grid, customer service, and a distribution network to deliver electricity to customers.

2.1. Marginal Customer Access Costs

Marginal Customer Access Costs (MCAC) represent the incremental costs of connecting an additional (*i.e.*, marginal) customer to the grid that are not driven by volumetric energy usage or demand. The two cost components of MCAC are: 1) the marginal customer equipment costs (MCEC) consisting of final line transformer, service line drop, and meter costs, and 2) the ongoing and variable Revenue Cycle Service (RCS) costs associated with keeping customers connected to the grid, such as customer billing, meter reading, and credit and collections.

[5] *See* D.18-08-013, COL 8 ("[o]ther considerations may lead us to find that deviations from…marginal cost-based revenue allocation rate designs are reasonable, as we do in this proceeding").

2.1.1. Calculating MCEC

One of the primary debates in this proceeding concerns the method for calculating MCEC. The reason for competing methodologies is that the cost (or value) of a final line transformer, service line drop, and meter for a new PG&E customer is not immediately apparent. As noted by Cal Advocates, new customers hooking up to PG&E are not charged the full value of this equipment at the time of hook-up, and as a result the price signal that would otherwise exist is muted. Instead, "the costs associated with connecting an additional customer [are] collected from all ratepayers through service line extension allowances. These allowances provide a mechanism to socialize the large up-front costs of connecting a new customer to all ratepayers such that each ratepayer pays a small portion of the costs associated with connecting a new customer to the grid."[6]

As a result of the failure to price and impose the actual cost of MCEC on a new customer, it is necessary to create a value for the equipment in order to establish a marginal cost for an incremental customer to access the grid. This may be done in a variety of ways, and the parties in this proceeding do not agree on exactly how to value MCEC.

PG&E proposed using the Real Economic Carrying Cost (RECC or rental) method for determining the value of MCEC. The RECC method applies carrying charges to the components of transformers, service drops, and meters (TSM) in order to develop the revenue requirement associated with recovering return of and on capital and associated income taxes.[7] In this way, the RECC method

[6] Exhibit (Exh.) Cal Advocates-01 at 1-4.

[7] FEA Opening Brief (OB) at 3.

attempts to calculate the value of all extant equipment used to connect a customer to a grid, regardless of the age of the equipment or whether it is used to connect a new customer to the grid. Several parties supported PG&E's use of the RECC method to calculate MCEC, including FEA,[8] CLECA,[9] and EPUC.[10]

PG&E's reasoning in favor of the RECC method centered on the argument that it is consistent with marginal cost definition and theory because it divides the cost of connecting new customers by the number of new customers.[11] The RECC method achieves this, according to PG&E, by calculating an "appropriate annual credit and recover[s] the meter costs within a reasonable time horizon, using an illustrative hypothetical customer who chooses to install his/her own meter and asks PG&E for an annual credit."[12] CLECA also advanced arguments in favor of the RECC method, claiming that:

> The RECC method provides correct pricing for customer access to the utility system regardless of location. Customers are constantly entering and exiting utility service, and may take service at an existing location or a new location. Houses, buildings, factories, etc. are not regularly replaced, but the opportunity cost of TSM facilities that are left behind by an existing customer is still a cost to the utility system. There are ongoing financing costs of existing and new TSM facilities that must be recovered. In addition, the utility must maintain the facilities at each service location; alternatively, the equipment could be used at another location to provide access for a similar type of customer. The opportunity cost of the TSM facilities is the installed facility cost times the RECC factor,

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[8] FEA OB at 3.

[9] CLECA OB at 3.

[10] EPUC OB at 3.

[11] PG&E OB at 19.

[12] PG&E OB at 21.

which calculates the annual value in real dollars of deferring the investment by one year.[13]

AECA clarified that even though the RECC method focuses on the cost of new connection equipment installed to meet the needs of new customers, "[t]he RECC method takes the long-term cost to serve a new customer and presumes that the RECC is the 'market' price of service for all customers, new and existing."[14] The RECC method therefore attempts to assign a cost for connection equipment to existing customers in the form of an annual rental fee that is based on new equipment costs, hence the alternative name for the RECC method – the rental method.

Cal Advocates and TURN disagreed with PG&E's methodology for calculating MCEC, and argued that the Commission should adopt the New Customer Only (NCO) method for calculating MCEC. The NCO method calculates the total capital cost of hooking up a customer and multiplies it by the number of new customers added in a particular year, with an adjustment made to recognize replacements of equipment.[15] Cal Advocates' proposed NCO methodology is based upon: 1) 2018 historic new customer connections for calculating growth rates, 2) a uniform growth rate for all non-residential classes, and 3) recovery of meter operations and maintenance (O&M) costs through a lifetime meter O&M adder.[16] CFBF and SBUA also supported using the NCO method as opposed to the RECC method.[17]

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[13] CLECA OB at 8-9.

[14] AECA OB at 10.

[15] FEA OB at 3.

[16] Cal Advocates' OB at 3.

[17] CFBF OB at 2-3; SBUA OB at 3 (SBUA also supported the embedded cost approach advanced by DACC).

Cal Advocates outlined three principal reasons for its support of the NCO method: 1) NCO is an appropriate short-run marginal cost method, 2) NCO more accurately reflects how connection equipment costs are incurred, and 3) NCO produces a more actionable price signal for customers.[18]

In general, Cal Advocates argued that the NCO method should be used because "the NCO method for determining MCEC is a superior proxy for marginal costs and more accurately reflects how customer connection costs are incurred."[19] Cal Advocates noted that NCO calculates the MCEC by multiplying the present value of the connection equipment with the growth rate for the customer class, and reasoned that by using two empirical values the NCO produces a "real world" estimate of the marginal cost of MCEC. Unlike PG&E, Cal Advocates does not believe existing connection equipment should be valued as part of the MCEC calculation because, by definition, existing equipment cannot be marginal. Cal Advocates argued that NCO was therefore inherently more accurate than, and superior to, PG&E's RECC methodology.[20]

Cal Advocates noted that the Commission has previously found that the NCO provides a better "price signal" than RECC, given that the NCO method treats connection equipment for existing customers as sunk costs. D.96-04-050 held that the "NCO method appropriately reflects the factors that cause Edison's investment-related customer costs to increase, i.e., new customers on the system

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[18] Exh. Cal Advocates-01 at 1-6.

[19] Exh. Cal Advocates-01 at 1-2.

[20] Cal Advocates also argued that the NCO was superior because it sent a more actionable price signal to customers, but this decision does not consider that argument.

and hookup replacements. No such corresponding investments are required for customers that already have an operating hookup installed."[21]

TURN echoed this argument by pointing out that recently litigated cases before the Commission have resulted in Commission support for the NCO method. TURN asserted that "[t]he Commission has adopted the NCO method in prior litigated cases for all of the major electric and gas utilities in the state with the exception of [San Diego Gas & Electric Company's (SDG&E's)] electric department, where settlements have simply averaged revenue allocation numbers from four different cost studies including both Rental and NCO. The NCO method has been adopted in three PG&E [Biennial Cost Allocation Proceedings (BCAPs)] and two litigated PG&E electric cases, the 1996 rate design case for Edison, and the 1996 SDG&E gas BCAP, and the 1999 consolidated SoCal and SDG&E BCAP."[22]

With respect to the RECC methodology itself, Cal Advocates was unsparing and attacked the use by PG&E of the concept of deferral to justify the RECC. Cal Advocates argued that "[u]sing the RECC method to estimate marginal cost fails a basic logical test: there is no practical scenario where an existing customer can decrease use of their connection equipment for a new customer's use at a different premise simultaneously, thus deferring the need to install new connection equipment."[23] Cal Advocates pointed out that this

[21] Exh. Cal Advocates-01 at 1-8, citing D.96-04-050 at 65.

[22] Exh. TURN-01 at 3.

[23] Exh. Cal Advocates-01 at 1-9.

argument helped to persuade the Commission to adopt the NCO methodology with respect to Southern California Edison Company's (SCE's) MCEC in 1996.[24]

TURN made similar arguments in support of the NCO. First, they also criticized the deferral argument reasoning that "[a] customer facility cannot be used by another customer at another location. By contrast, energy, generation capacity, and to a lesser extent transmission and distribution capacity, are more common or fungible costs."[25] TURN also argued that the NCO accurately reflects the incremental costs that might face a customer when deciding to access PG&E's grid from a position outside the grid (*i.e.*, as either a new customer or returning customer) because the correct way of interpreting marginal costs related to customer hook up was to recall that "the marginal cost resulting from the utility's decision to supply the extra unit of customer-hookup equipment is only a function of the change in the total cost to the company resulting from procuring and installing the extra unit to a single premises."[26] The RECC method has a different perspective, according to TURN, which "simply dresses up sunk embedded costs in marginal cost trappings."[27]

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[24] Exh. Cal Advocates-01 at 1-10, citing D.96-04-050 at 66 ("[a]s Edison acknowledges, equipment attached to buildings does not have opportunity value on its own separate from the building in which the equipment is installed… Moreover, customer hookup equipment has negligible salvage value…. In short, Edison cannot use the hookup installed at an existing location to serve a new customer on its system or replace a hookup for an existing customer. In this way, customer access equipment is significantly different both from other gas and electric plant and from the buildings to which it is attached. The NCO method appropriately reflects this difference").

[25] Exh. TURN-01 at 5-6 ("with the exception of salvage value of meters and transformers, the equipment serving a customer facility has no value apart from the location where it exists").

[26] Exh. TURN-01 at 4.

[27] Exh. TURN-01 at 3.

Expanding on this point, TURN argued that the NCO better fulfilled specific goals for marginal cost-derived rates expressed by the Commission. TURN noted that the "Commission has stated that marginal costs should reflect the timing of new additions (D.90-07-055, and D.92-12-057)" and asserted that the NCO method "reflects the timing of new additions because it is based on the number of new customer additions during that period and is not spread over the utility's average number of existing customers," as the RECC method would do.[28] TURN further argued that the NCO is superior to RECC with respect to reflecting incremental demand and cost causation given that the NCO reflects costs imposed at the time the customer hooks up to PG&E's grid.[29]

TURN criticized the RECC method for reasons beyond its valuation of embedded costs. TURN argued that the RECC method systematically utilized higher hookup costs derived from more modern, suburban developments (*i.e.*, underground hookup equipment) and then applied those costs to all customers, including those living in apartment buildings or other urban development that would have lower hookup costs on the margin (*i.e.*, overground hookup equipment). TURN asserted that "underestimating the percentage of apartments would overstate rental method capital cost by hundreds of dollars"[30] and that only 5.88 percent of customers in PG&E's hookup cost database were hooked up with lower-cost overhead equipment.[31] TURN argued that because PG&E's hookup cost database contained substantial gaps and inaccuracies (*e.g.*, listing 38 percent of the housing stock as "unknown" as to whether it is served by

[28] Exh. TURN-01 at 7.

[29] Exh. TURN-01 at 7-8.

[30] Exh. TURN-01 at 10.

[31] Exh. TURN-01 at 14.

overhead or underground hookup equipment), the RECC method could not be corrected to compensate for this inequitable assignment of costs.[32]

2.1.2. MCEC and the Valuation of Existing Equipment

DACC invited the Commission to consider an extreme solution for settling the MCEC methodological dispute. DACC stated that they were "skeptical that marginal cost allocation is appropriate for allocating customer access distribution costs."[33] DACC reasoned that because MCEC marginal costs did not send an actionable price signal to potential utility customers if it was baked into volumetric rates or demand charges, it was not necessary to estimate MCEC at all.[34] They recommended that an embedded cost approach be used instead.[35]

The Commission does not agree that MCEC calculations should be replaced with an embedded cost analysis. First, this decision disagrees with DACC and SBUA and finds that a marginal access price signal is capable of being sent to a potential utility customer. As noted by Cal Advocates, there is a marginal cost signal being sent to new customers that hook up to the grid, although this signal may be socialized through the use of line extension allowances.[36] Second, in previous decisions, the Commission has made quite clear its support for the use of marginal costs for determining revenue allocation

[32] Exh. TURN-01 at 15.

[33] Exh. DACC-01 at 9.

[34] Exh. DACC-01 at 10.

[35] Exh. DACC-01 at 12, clarifying that all customer connection costs for a class should simply be summed for that class and then divided among the class members. SBUA supported this approach. (SBUA OB at 4.)

[36] Exh. Cal Advocates-01 at 1-3 and 1-4.

and rate design.[37] Adopting the embedded cost approach proposed by DACC would not align with Commission precedent or the principles laid out in this decision. The question before us is how to calculate the marginal cost of customer access equipment. With respect to DACC's skepticism, the Scottish empiricist David Hume once wrote:

> No philosophical dogmatist denies that there are difficulties both with regard to the senses and to all science, and that these difficulties are, in a regular, logical method, absolutely insolvable. No skeptic denies that we lie under an absolute necessity, notwithstanding these difficulties, of thinking, and believing, and reasoning, with regard to all kinds of subjects, and even of frequently assenting with confidence and security. The only difference, then, between these sects, if they merit that name, is that the skeptic, from habit, caprice, or inclination, insists most on the difficulties; the dogmatist, for like reasons, on the necessity.[38]

Here the Commission is faced with a decision which, using Hume's expression, is a necessity that must be embraced to settle the parties' dispute concerning MCEC. There are dogmatic arguments on either side of this issue that simply have no empirical basis for acceptance or rejection.[39] But this condition of the argument must not prevent the Commission from making a determination. Like a skeptic confronted by necessity, this decision must adopt a methodology for calculating MCEC that is best suited to the record of this

[37] PG&E OB at 10 ("[f]or over 40 years the [Commission] has used marginal costs for purposes of electric revenue allocation and rate design"), citing D.92749 at 2. *See also* D.18-08-013, *passim*.

[38] Hume, D., *Dialogues Concerning Natural Religion*, Part XII, note 27.

[39] *See, e.g.,* Exh. DACC-01 at 12 ("[t]he NCO versus RECC method debate has been going on for over 30 years. Both sides claim to be right, generally using the same arguments year after year. I find both sides' arguments to contain fatal flaws"); AECA OB at 12 ("[p]arties' rigid adherence to comfortable positions is not productive in terms of developing an accurate, theoretically sound methodology for calculating marginal customer energy costs").

proceeding and the arguments made by the parties. To do otherwise would open a question of whether MCEC should be valued at all, and as discussed previously this decision declines to proceed down that path.

The argument surrounding RECC and NCO methods can be boiled down to one key question: is it appropriate to only use the costs associated with new investments in access equipment in a given year when determining the value of MCEC, or may a value be assigned to existing assets as well even if those existing assets were previously used to hook up a marginal customer? Cal Advocates argued that the RECC method is flawed in its valuation of existing equipment as it is based on the concept that the cost of new equipment to connect a new customer can be deferred by an existing customer vacating their home or business. Cal Advocates claimed that, "[w]hile this is possible in theory, significant relocation, and other transaction costs make this an impractical way to frame the issue."[40] TURN made similar arguments regarding the deferral issue, and stated that "[f]rom the point of view of marginal cost theory, customer access is best considered a one-time event, with the costs of that event best recovered through a hookup charge."[41] TURN distilled its deferral argument by claiming that MCEC "are tied to a customer facility at a specific location and are only avoidable at the time of installation. These facilities cannot be used by another customer at another location."[42]

Marginal customer access doubtless occurs when new access equipment is installed. But it also occurs whenever a customer moves from one location to another, or when a new customer moves into a location with existing access

[40] Cal Advocates OB at 4.

[41] Exh. TURN-01 at 3.

[42] TURN OB at 4.

equipment. At the new location, the customer most likely uses existing equipment to access the grid.[43] While the equipment itself may be existing, it has value as facilitating incremental (and therefore marginal) customer access.[44] The deferral argument against the RECC method made by Cal Advocates and TURN is premised on the assumption that it is impractical to rip existing access equipment out of a home or business and give it to a new customer to use as their initial connection equipment. That would indeed be impractical, but that is not the premise adopted by this decision for the reasons detailed below. Because the last Commission decision (D.96-04-050) to address the issue of MCEC methodologies adopted the NCO method partially on the basis of the deferral argument,[45] this decision should be read as revising Commission precedent on this issue.

Consider the example of a home that is occupied for many years by the same utility customer. If the occupant vacates the home and terminates their utility service, the utility faces two choices: 1) it can remove the access equipment and then install new equipment if/when a new customer moves into the home and starts utility service, or 2) it can leave the existing equipment in place until

[43] A PG&E response to Energy Division data request showed that while 1.2 percent of residential customers installed new hookup equipment in 2020, between 4.2 and 5.4 percent of residential customers moved from one location to another and took advantage of existing access equipment in 2020. Contrast with TURN's argument that "the NCO method is more demand sensitive than the rental method since it reflects new demand for new customer access equipment." (TURN OB at 6.) TURN's argument disregards the demand for incremental connections created by new customers that move into locations with existing connection equipment.

[44] TURN argued that "[a] customer facility cannot be used by another customer at another location." (Exh. TURN-01 at 5.) While this is true, a customer facility may be used by another customer at that location in the future, and in theory multiple times over the lifetime of the equipment.

[45] TURN OB at 7, citing D.96-04-050 at 65-67.

such time when a new customer moves into the home and starts utility service. If the utility chooses the second option, it is reasonable to view the existing equipment as fulfilling a discrete function to provide incremental access to a new customer. There is, in fact, no other reason for the utility to leave the existing equipment in place, and therefore the function of providing incremental access is literally the only function of the existing equipment once the old customer cancels utility service.

This example illustrates a common expectation among utility customers that they may reliably make use of access equipment within the utility's territory – either newly installed or existing. Based on the perspective outlined above, existing access equipment should be valued as providing the ability to incrementally provide customer access to the grid. Because it is not known which piece of existing equipment may be utilized for incremental customer access at any given time, it is appropriate to assign a value to all such existing equipment that reflects its capacity to provide access to an incremental customer.

One could argue that new customers are not imposing marginal costs if they use existing equipment because the cost of existing equipment was incurred in the past to provide access to a (then) new customer, and is therefore by definition not a marginal cost to the utility.[46] However, there is a difference between a cost that is sunk and an asset that is *valueless*.[47] The record does not

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[46] *See* TURN OB at 5-6 ("[s]ince existing customers do not impose new connection costs, they should not be assumed to impose marginal costs on the system… Once the customer has decided to hookup, costs become sunk and society cannot avoid them (except for the salvage value associated with removable equipment such as regulators and meters)").

[47] CLECA OB at 9 ("a new customer who's come in and asked for access at the same [existing] location. They step into the cost. There are capital costs associated with that investment over the lifetime of that investment. And that's the marginal cost of access…").

reflect that existing customer access equipment is valueless.[48] In fact, the record establishes that existing equipment does have some value, even if only as scrap. PG&E is continuing to pay for its existing customer access equipment through operations and maintenance, as well as holding the equipment on its books as an asset (and deriving a rate of return, which the RECC method's carrying costs attempt to capture). As illustrated above, once an old customer terminates utility service the existing equipment transforms into equipment that is waiting to provide incremental access.[49] A new customer that uses existing equipment should appropriately assume the marginal cost of that asset – both its operational costs and its depreciated value.

The question then is how to value existing access equipment. The RECC method seeks to value all existing access equipment as if it were new equipment,[50] and then appropriately annualize that value over a given number of years. As noted by several parties, including CFBF, this approach is illogical.[51] Existing equipment that may be used for customer access is plainly not new and should not be valued as such.[52]

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[48] AECA OB at 10 ("[t]he concept that an existing connection has zero value is false").

[49] *See, e.g.,* CLECA Reply Brief (RB) at 2 ("[t]he equipment is left in place because there is still a marginal need for access at a particular location, even if the customer changes").

[50] Exh. DACC-01 at 5 (under PG&E's RECC method "[TSM] costs for a connection are determined for each customer class using the actual new connection contract cost data").

[51] CFBF OB at 3 ("[t]he assumption in the RECC method that a customer's opportunity costs are equal to the cost of a new hookup is clearly incorrect").

[52] *See* Cal Advocates OB at 5 ("the RECC method effectively assumes that a larger percentage of TSM hookups are underground than does the NCO method… [and underground] connections are more expensive than overhead connections"); TURN OB at 12 ("[t]he rental method also ignores the extent to which new customer connections differ from existing customer connections and assumes the costs of both types of connections are identical. The failure to give any consideration to relevant differences results in skewed outcomes").

AECA offers a method of utilizing the RECC method while also accounting for the difference in costs between existing equipment and new equipment. AECA proposed that the cost of new connections be considered one component of the MCEC, and "the value to existing customers who sell their utility connections to other buyers" (*i.e.*, the value of existing connection equipment) be considered a different component.[53] For new connections, AECA supports using the RECC method. For existing connection equipment, they recommended using the "replacement cost new less depreciation" methodology where the weighted average age of the different segments of the connection cost (i.e., TSM costs) is utilized.[54] The total marginal customer equipment cost is then calculated by "adding the sum of the remaining value in the TSM and the sum of new connection costs, and dividing by total customer connections, new and existing."[55] They claimed that this approach has been utilized by the Commission in the past in other contexts, and would enhance equitable allocation of connection costs between customers.[56]

In response to arguments put forward by AECA that existing and new access equipment costs can be viewed in a manner similar to new vs. used cars, PG&E claimed that meters are not analogous to cars and that existing and new access equipment should be equally valued at the cost of new equipment because

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[53] AECA OB at 8.

[54] AECA OB at 11.

[55] AECA OB at 11-12.

[56] AECA OB at 11. *See* D.03-04-042, where PG&E used the replacement cost new less depreciation method when selling assets that were municipalized.

the service they provide – grid access – is identical.[57] However, a car may be a useful analogy for explaining why it is appropriate to value existing and new access equipment differently. A car provides a driver with access to a critical kind of infrastructure. In the case of a car, the infrastructure consists of roads. While the road access that a used and new car provide may be identical, as noted by PG&E, the market prices cars in very different ways depending on whether the car is new or used. Higher prices for new cars may reflect a variety of considerations – the smell of off-gassing plastic, absent dents and dings, neighborhood bragging rights – but one of the critical considerations is depreciation. The moment a car is driven off the lot it loses a significant amount of value through presumed depreciation.[58] Such depreciation is a benefit to used car buyers that seek a value proposition for their road access. In this sense, the identical-access argument put forward by PG&E misses the point. So long as there are differences in the price to achieve identical access, those differences should be reflected in MCEC calculations.

Applying the RECC method as proposed by PG&E would essentially charge all customers "new car" prices for their used access equipment. It is not relevant that the service provided by the access equipment is identical. Instead, as a matter of fairness, the Commission should not assign marginal costs (and therefore marginal cost revenues) to a customer class that are not aligned with

[57] PG&E OB at 22 ("there is certainly a different quality of service and driving experience as between driving a brand-new car versus a decades-old car. But this clearly doesn't hold for meters, where the quality of service for the customer is the same regardless of the age of their meter").

[58] AECA OB at 10 ("[d]epreciation is based on the principle that the increasing costs of maintaining sufficient quality, reliability and safety eventually rise to a point where those costs exceed the cost of a new replacement. PG&E inexplicably alleges that this fundamental principle of depreciation does not apply to service connections, which is false").

the actual value of marginal equipment. As discussed previously, it is reasonable to treat existing equipment as allowing for incremental customer connections; it is not reasonable, however, to misvalue that equipment. As noted by TURN, "[t]he most economically efficient method for capturing the costs of access equipment would be in the form of a customer hookup fee that charges the access equipment costs to the customer."[59] Modifying the RECC method to value existing equipment at an appropriate depreciated value captures the essence of this proposed hookup fee.

For the reasons described above, PG&E shall use the RECC method to calculate the MCEC and shall modify its RECC methodology so that it accounts for the remaining lives of the assets in place and the differentials in customer growth rates. New connection equipment may be valued using the RECC method, but existing equipment shall be valued using the "replacement cost new less depreciation" method as described by AECA in its briefing.[60] Modification of the RECC method in this way accurately reflects both the value of new connection equipment and existing connection equipment that may be used to calculate the MCEC, and is therefore reasonable to adopt.

2.1.3. Calculating RCS

PG&E proposed to calculate RCS based on an average of recorded 2015-2017 costs. Specifically, PG&E claimed that there are over 40 activities in its RCS model that reflect PG&E's current billing and payments, credit and collections, customer inquiry, meter services and meter reading operations. They are grouped into five major RCS categories: 1) account set-up, 2) billing and

[59] TURN OB at 5.

[60] CLECA supported the use of the replacement cost new less depreciation method in the event the Commission wished to apply depreciation to existing MCEC assets. (CLECA RB at 6-7.)

payments, 3) credit and collections, 4) meter services, and 5) meter reading. Each RCS activity type coincides with a unique cost driver (for example, the cost driver for electronic bill delivery costs is the number of electronic bills delivered). There are three categories of RCS model input data: 1) financial costs, 2) cost drivers (from the PG&E departments responsible for the underlying services), and 3) customer data (from PG&E's billing system).[61]

While most parties accepted PG&E's calculations, TURN disputed elements of PG&E's proposal. TURN argued that the Commission should calculate PG&E's RCS costs based on 2017 costs with a five percent discount to all functions to reflect technological change after 2017 and cost data provided in PG&E's GRC Phase 1 proceeding. TURN further suggested that SmartMeter opt-out costs should be excluded from the RCS results. Cal Advocates also proposed an adjustment to PG&E's calculations, recommending that the calculation should include a new lifetime meter O&M adder based on the use of the NCO methodology.

With respect to the lifetime O&M adder issue, as this decision has already found that an adjusted version of the RECC methodology should be used to calculate the marginal cost of customer meters, it would be inappropriate to include a lifetime O&M meter adder based on the NCO method. Further, PG&E asserted that its "RCS model's annual meter repair and maintenance data are based on activity specific and customer specific job costs, thereby providing a more accurate O&M cost estimate than the NCO Method's generalized lifetime

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[61] PG&E OB at 26-27.

O&M costs."[62] This decision concurs and declines to adopt a lifetime O&M adder for meters as proposed by Cal Advocates.

TURN asserted that its proposed discount approach was justified by the record of this proceeding. TURN cited figures from PG&E's workpapers showing that PG&E's total RCS Costs (in 2021 dollars) declined by 20.3 percent between 2015 and 2017 (from $243.8 million in 2015 to $213.7 million in 2016, and further to $194.4 million in 2017). TURN believed that the decline in costs could be attributed to increases in productivity resulting from technological change, and that it is reasonable to assume these cost decreases will continue in the future as technology improves.[63]

TURN reasoned that marginal cost values should be forward-looking, rather than retrospective, and therefore PG&E's failure to judge marginal RCS costs in terms of increased productivity since 2017 was in error.[64] TURN pointed out that, with respect to marginal generation capacity costs, PG&E was employing a prospective approach by examining lithium-ion battery costs. TURN argued that such an approach should be used for marginal RCS costs as well.

PG&E opposed TURN's proposal, arguing that by using only a single year of RCS costs (from 2017) for its calculations, TURN may allow for the RCS model to be skewed if the data from that year are unrepresentative. PG&E argued that its multi-year averaging approach helps to smooth out annual variations in the

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[62] PG&E OB at 27.

[63] Exh. TURN-01 at 17-18.

[64] Exh. TURN-01 at 18 ("PG&E proposes an average of 2015-2017 costs as the basis for its RCS costs to be effective in 2021, despite the 20 [percent] decline between 2015 and 2017 and the additionally projected decreases in costs in the 2020 Phase 1 GRC. PG&E's average thus overstates even relatively current recorded (2017) results, much less future conditions").

data.[65] While PG&E granted that technological change may lead to future cost savings, they criticized TURN's blanket five percent discount as not accounting for potential future increases to costs such as inflation. PG&E also asserted that TURN misread PG&E's GRC Phase 1 testimony, and that the decline in real dollars evidenced by that testimony is only two percent from 2017 to 2020.[66]

Finally, PG&E opposed TURN's discount proposal as lacking in rigor, given that "TURN has stated in a data response that no specific methodology or set of calculations [was used] to come up with the five percent reduction recommendation."[67]

PG&E's reasoning on this point is persuasive. PG&E's use of several years of data smooth out potential annual variations that might skew the performance of the RCS model if only a single year's worth of data is used. Further, the heterogenous nature of RCS costs means that the use of a blanket five percent discount, apparently calculated without a specific methodology in mind, would likely not accurately reflect changes to actual RCS costs that could be observed over time. Therefore, this decision adopts PG&E's RCS calculations and does not adopt TURN's proposed five percent discount.

With respect to the SmartMeter opt-out issue, TURN believed that the cost of reading legacy meters should be removed from the RCS calculation, if PG&E's proposal is adopted, as such costs are not marginal for 99 percent of PG&E's customers and are assessed only as a matter of Commission policy.[68] However, PG&E responded that the costs could be considered part of a marginal cost

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[65] PG&E OB at 28-29.

[66] PG&E OB at 29-30.

[67] PG&E OB at 30.

[68] Exh. TURN-01 at 22-23.

calculation given that "so long as there is a SmartMeter opt-out program, the costs of manually reading opt-out customers' meters should be included in the marginal cost calculation since a new customer can also elect to be in the SmartMeter opt-out program."[69]

PG&E's reasoning on this point is also persuasive. As previously held in this decision, existing meters should be considered potentially marginal, meaning that TURN's logic for excluding the legacy meter reading costs is unfounded. Therefore, it is appropriate to include the SmartMeter opt-out costs in PG&E's RCS model.

2.2. Marginal Distribution Capacity Costs

Marginal Distribution Capacity Costs (MDCC) are utilized in PG&E's revenue allocation process to assign distribution revenue responsibilities to different customer classes. MDCC reflect the capital investments needed to serve an incremental kilowatt (kW) of load. MDCC include primary distribution costs (*e.g.*, existing distribution substations and mainline (primary) distribution feeders), new business primary distribution costs (e.g., primary line extensions necessary to serve the demand of new customers), and secondary distribution costs (*e.g.,* capacity investments made to address demand growth on the existing system).[70]

PG&E proposed to estimate MDCC at primary and secondary voltage levels using forecasted peak demand growth and the corresponding investments

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[69] PG&E OB at 32.

[70] "Primary" and "secondary" refer to the different voltages used on distribution infrastructure. Primary is defined as equipment that uses between 4 kilovolts (kV) and 60 kV, and secondary uses less than 4 kV. Secondary MDCC explicitly exclude transformer, meter, and service costs separately considered as MCAC even though that equipment is technically secondary distribution equipment. (Exh. PG&E-02 at 7-2 and 7-3, 7-4 at fn 4.)

(*i.e.*, capital additions), based on two methods: 1) Discounted Total Investment Method (DTIM) and 2) National Economic Research Associates (NERA) Economic Consulting's Regression Method (RM). PG&E recommended that the Commission adopt the DTIM as opposed to the RM for calculating MDCC.[71] PG&E utilized a different method of estimating the geographic granularity of MDCC in this proceeding compared to previous GRC Phase 2 applications. PG&E used circuit level peak demand data to estimate demand growth and produce a cost driver that PG&E believed "is directly correlated to capital investment because PG&E conducts the distribution investment planning process at the circuit level."[72]

2.2.1. DTIM and RM Methodologies

CLECA argued against the use of the DTIM method and instead supported the NERA RM methodology, with the use of ten years of historical and five years of forecast investment regressed against maximum demand growth for the same period. CLECA reasoned that since the DTIM method deals solely with forecasted MDCC investments, the costs of those investments are discounted compared to present investments, and the marginal costs calculated using DTIM are therefore undervalued compared to the marginal distribution costs imposed by customers today.[73] CLECA claimed that their RM method allowed for the smoothing out of "lumpy" investments in distribution

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[71] Exh. PG&E-02 at 7-1.

[72] *Id*. PG&E also argued that the historic geographic granularity used to calculate MDCC may have produced absurd results in this GRC Phase 2 proceeding (Exh. PG&E-02 at 7-6).

[73] CLECA OB at 44.

equipment by using 10 or 15 years' worth of data, and cited the historic use of the RM by the Commission in support of its proposal.[74]

CLECA also proposed that MDCC estimates at the system-level be used instead of the geographically differentiated MDCC estimates presented by PG&E. CLECA argued that as the Commission does not set division-specific distribution rates, it is not necessary to calculate division-specific marginal costs for distribution.[75]

Other than CLECA, no party disputed the use of the DTIM method for calculating MDCC.

PG&E opposed CLECA's recommendation to use the RM method due to its reliance on ten years of historical data, which in PG&E's view would not properly reflect the forward-looking design criteria used in PG&E's distribution system planning, and due to the apparent lack of relationship between historical investment and historical load growth. Furthermore, PG&E believed that the model itself was too weighted toward historic data and therefore was too inelastic in response to changes in forecasted demand.[76] PG&E also claimed that the use of historic data was not appropriate as it would not allow for the consideration of potential future weather and technology mandates that would drive incremental demand higher than what was experienced in the past.[77]

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[74] CLECA OB at 44-45.

[75] CLECA OB at 46.

[76] PG&E OB at 94.

[77] PG&E RB at 45 ("[t]his lack of reasonable responsiveness means that the MDCC estimates from [RM] show negligible change in the MDCC estimates when the forecast input data changes are significant. Input load data can change significantly in coming years due to adoption of solar and battery storage, electrification, and response to climate change. CLECA ignores this very important issue").

With respect to CLECA's suggestion that a less geographically granular approach to MDCC should be used, PG&E offered that any level of geographic granularity was acceptable, but that PG&E's recommended approach should be adopted as consistent with historic practice and Commission precedent.[78]

Given that PG&E's approach is consistent with Commission precedent, and allows for changes in MDCC values that may result from expected future investments due to technology mandates and climate change that are not accounted for in the historic data used by RM, it is reasonable to adopt PG&E's DTIM method for calculating MDCC.

2.2.2. Cal Advocates' Proposed DTIM Adjustment

Cal Advocates proposed in their testimony an adjustment to PG&E's proposed DTIM method of calculating MDCC that includes five years of historical investment and load data in the calculation. Cal Advocates offered two justifications for the inclusion of historic investment and load data: 1) the historic data represent the true, real amount of electricity capacity and investment that PG&E provided to expand its distribution capacity system, and is thus "inherently more accurate than the forecasted data" exclusively used by PG&E, and 2) the marginal cost estimated are "less erratic with more distribution load and investment inputs" because it compensates for the inherent unknowns in forecasting future marginal cost values. Cal Advocates does not object to the use of forecasted data, recognizing that it is necessary to produce forward-looking cost estimates, but Cal Advocates asserts that using historic data alongside forecasted data improves marginal cost forecasting.[79]

[78] PG&E OB at 95-96.

[79] Exh. Cal Advocates-01 at 2-10.

Cal Advocates supports its assertions with evidence that the marginal distribution load and investment forecast used by PG&E in its 2017 GRC Phase 2 differed from the actual distribution load and investments costs reported as historic data in PG&E's 2020 GRC Phase 2. For example, Cal Advocates demonstrated that "in its 2017 NERA and 2017 DTIM models, PG&E predicted marginal annual load increases of 759.26 megawatts (MW), 391.78 MW, and 312.92 MW on its distribution system for the years 2015, 2016, and 2017, respectively. However, PG&E's 2020 NERA model shows that the actual annual load increased by 473.76 MWs, 310.27 MW, and 555.96 MW for those same years. It is clear there are large differences between what is forecasted and how reality plays out."[80]

PG&E disagreed with Cal Advocates, essentially arguing that because MDCC calculations should be forward-looking, it was appropriate to only use forecasted load growth in the calculation. In particular, PG&E claimed that using "historical data introduces inconsistency for MDCC analysis and creates discrepancies between historical load growth that reflects actual weather and economic conditions, which are very different than the assumptions governing historical investment decisions."[81] PG&E elaborated by claiming that historical load growth has no causal relationship to historical investments, meaning that the use of historic data would not actually assist with accurate calculation of MDCC, and that the inclusion of historical data causes the Net Present Value (NPV) component of the DTIM calculation to over-weight MDCC estimates towards historical data.[82] Thus, PG&E argued, the volatility identified by Cal

[80] Exh. Cal Advocates-01 at 2-15.

[81] PG&E OB at 91.

[82] PG&E OB at 92.

Advocates "ignores the legitimate reasons why historical data is expected to be different from forecasts" and Cal Advocates' argument should therefore be rejected.[83]

As this decision approves PG&E's DTIM method for calculating MDCC, it rejects the proposal by Cal Advocates. As before, the use of historic data may not adequately allow for planned future investments in MDCC that may dramatically increase as compared to historic values due to technology mandates or the impacts of climate change.

2.2.3. Distribution Planning Area-Level Forecasting for Projects Less Than $1 Million in Value

Cal Advocates recommended that PG&E include in its next MDCC forecast an estimate of sub-$1 million projects that occur at the distribution planning area (DPA) level of granularity (as is done with projects exceeding $1 million in value) instead of the current practice of aggregating sub-$1 million project estimates to the division and/or system level.[84] Cal Advocates sought this change in order to attempt to uncover the reasons for an apparent increase in marginal distribution costs at the same time marginal distribution load is forecasted to decrease. For example, Cal Advocates suggested that if PG&E was experiencing less load at the division-level, but only a few DPAs within that division were driving the overall reduced load while other experienced increasing load, then Cal Advocates would not be able to tell if PG&E's load-

[83] *Id.*

[84] Exh. Cal Advocates-01 at 2-21.

driven distribution investments at the division level were appropriate without knowing the investments attributable to each DPA within a division.[85]

PG&E claimed that it would be impractical for the Commission to adopt Cal Advocates' recommendation. PG&E stated this is because "projects under $1 million are smaller, more common types of investments that are not planned for specific circuits or substations far in advance. Although these smaller investments are not known by PG&E's 3,200 circuits, and thus not readily able to be attributed to PG&E's ~240 DPAs, PG&E is reasonably able make geographically disaggregated estimates of the investment costs by its 19 operating divisions."[86] Finally, PG&E argued that forecasting such projects at the DPA level "would likely require many assumptions to be made and the resulting estimates would be of questionable accuracy."[87]

This decision notes that PG&E's forecasts of future load demand that drive MDCC are, in fact, forecasts. Being an educated guess, this decision finds that it is not unreasonable to require PG&E to forecast all of its MDCC investments at the DPA level. Doing so would enable parties to better understand the total forecasted investments that are driving the MDCC in each of the DPAs, instead of relying on the larger MDCC investments that might be forecasted for a particular DPA. With respect to PG&E's concern that such an analysis would be impractical, the Commission recommends that PG&E consult its records of MDCC investments in each of its DPAs in order to help it predict where such sub-$1 million investments might occur in the future given load forecasts for each DPA. While PG&E points out that the accuracy of such a forecast is a

[85] Cal Advocates RB at 13.

[86] PG&E OB at 96.

[87] PG&E OB at 97.

concern, this decision notes that the accuracy of PG&E's forecasted future MDCC investments are generally a concern regardless of the level of geographic granularity, and the Commission expects that PG&E will make a good faith effort to produce an accurate forecast of sub-$1 million MDCC investments for each of its DPAs for its next GRC Phase 2 application.

2.2.4. Uncontested MDCC Issues

There are two MDCC calculation issues that are undisputed by the parties: 1) PG&E's proposal to modify the method used to calculate incremental load growth by calculating only the absolute positive changes, and 2) Cal Advocates' proposal that PG&E update investment allocation factors for DTIM calculations in its next GRC.

Given that these issues are uncontested by the parties, it is reasonable to adopt them. PG&E shall modify its method used to calculate incremental load growth as described, and PG&E shall also update its investment allocation factors for DTIM calculations as recommended by Cal Advocates.

2.2.5. Distribution Peak Capacity Allocation Factors

To assign MDCC to each customer class, PG&E proposed to use its Peak Capacity Allocation Factor (PCAF) and Final Line Transformer (FLT) analyses, which examine the hours of highest loading on its distribution system equipment and the customer class contributions to the same.

Cal Advocates did not object to the use of PCAF and FLT analyses in principle, and supported the increased granularity exhibited by PG&E's PCAF and FLT datasets as compared to data used in previous GRC Phase 2 proceedings. Cal Advocates consequently recommended that the Commission adopt PG&E's proposed MDCC allocations in this proceeding.

However, Cal Advocates made clear that they were concerned by issues identified during their validation of the underlying PCAF and FLT data provided by PG&E, which "raised numerous issues around transparency, replicability, and the ability of other parties to access and analyze the data."[88] Among the issues detected by Cal Advocates' validation process were:

- the inclusion of dummy transformers and circuits that do not reflect loads for real transformers or circuits;
- issues categorizing customers that change rate schedules during the year;
- the accidental exclusion of certain rate schedules when mapping results to customer classes;
- the misidentification of net energy metering (NEM) and non-NEM customers; and
- the incorrect application of seasonal de-rating factors to distribution system loads.[89]

Cal Advocates noted that only PG&E has access to the complete set of underlying data, and therefore Cal Advocates could not confirm that the entire dataset was error-free even after correcting for errors detected by its validation.

To address these data issues going forward, in addition to concerns regarding variability in the data on a year-to-year basis that can be expected to be observed over time,[90] Cal Advocates recommended that the Commission direct PG&E to:

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[88] Exh. Cal Advocates-01 at 4-1.

[89] Exh. Cal Advocates-01 at 4-6.

[90] *See* Exh. Cal Advocates-01 at 4-11 and 4-12, showing that under PG&E's new approach classes could see year-to-year swings of over 1 percent of distribution cost allocation.

1) Provide a "sandboxed or testing coding environment"[91] in its next GRC Phase 2 application that allows parties to access, verify, and run their own analyses on the underlying datasets.

2) Construct a representative sample of FLT loads in its next GRC Phase 2, which will reduce the FLT dataset to a more manageable size and enable PG&E to make adjustments to reduce inter-annual variability.

3) At least eighteen months prior to filing its next GRC Phase 2 application, host a workshop to consider various methods to measure and reduce inter-annual variability in the PCAF and FLT cost allocation results, including use of multiple years in the analyses and weather normalization of loads. The overall purpose of the workshop would be to allow parties to discuss various options in detail and decide on the best course to address inter-annual variability in the dataset. PG&E should involve all parties in the scoping and design of the agreed-upon processes.

Given that there are apparent issues around transparency, reproducibility, and accessibility, as well as parties' abilities to analyze PG&E's PCAF and FLT data, it is reasonable to adopt some of Cal Advocates' recommendations. While a "sandboxed" coding environment is not mandated at this time, due partially to the cost of requiring such an environment, it is reasonable to seek a representative sample of FLT loads for use by the parties in PG&E's next GRC Phase 2 application. Therefore, PG&E shall, no later than July 2022, host a workshop to consider various methods to measure and reduce inter-annual variability in the PCAF and FLT cost allocation results, including use of multiple years in the analyses and weather normalization of loads. At the workshop, PG&E and the parties should discuss the nature of the representative sample to be constructed for the parties' use in PG&E's next GRC Phase 2 application.

[91] For example, "through Amazon Web Services, a cloud-based web environment that allows the purchaser to easily expand the computing technical specifications to allow for more users to access and work with the entire dataset." (Exh. Cal Advocates-01 at 4-8.)

PG&E shall include such a representative sample as part of its served workpapers in support of its opening testimony in its next GRC Phase 2 application. In order to explore the application of PG&E's MDCC PCAF approach to other utilities in California, SCE and SDG&E are invited to participate in the workshop and propose how they would apply this approach in their next GRC Phase 2 applications, including the submission of representative sample data.

3. Marginal Generation Costs

Marginal generation costs are composed of two components: marginal energy costs and marginal generation capacity costs. Each of these components is considered separately below.

3.1. Marginal Energy Costs

Marginal energy costs (MEC) are those costs to procure a marginal amount of energy. PG&E calculated the MEC for the purpose of revenue allocation and rate design in this proceeding by using hourly power price forecasts for Northern California for the periods January 1, 2021 through December 31, 2021. The hourly power price forecasts were based on the relationship between prices in the Day Ahead (DA) and Real-Time Markets (RTM) of the California Independent System Operator (CAISO), and load and generation in the CAISO, including the impacts of conditions in the rest of the Western Electricity Coordinating Council (WECC) and the operations of Energy Storage (ES) on prices of energy and Ancillary Services (A/S). PG&E used the DA and RTM markets for the source of their forecasts as that is where PG&E procures marginal energy.[92] The results of PG&E's MEC calculations by time-of-use (TOU) period and voltage level appear in Table 2-2 of Exhibit PG&E-02 at page 2-9.

Much of PG&E's proposal for MEC calculation is unopposed by the parties. Some parties did seek the inclusion of certain cost adders to the MECs produced by PG&E, as described more fully below, but did not challenge the overall approach taken by PG&E in computing MEC.

CLECA asserted that PG&E's MEC calculations are "not unreasonable" and that PG&E's approach to reflect the impact that energy storage will have on future energy price shapes is appropriate.

Given the general agreement of the parties on PG&E's methodology for calculating MEC, this decision finds that it is reasonable to adopt PG&E's proposed methodology for calculating MEC. Modifications made by this decision to the results of this methodology are described below.

3.1.1. Renewable Energy Certificate Adder

AECA argued that an adder to account for the costs of renewable energy certificates (RECs), taken from the most recent Market Price Benchmark (MPB), should be added to PG&E's estimated MECs. A REC adder is intended to account for the incremental procurement cost that must be undertaken by a utility to meet its renewables portfolio standard (RPS) mandates under Senate Bill (SB) 100. AECA argued that a REC adder was justified as it represents an incremental cost associated with the purchase of an additional unit of energy, and therefore should be included in a marginal energy cost calculation. AECA recommended that the Commission adopt a REC adder based on an MPB of $17.35 per megawatt-hour (MWh) based on a report produced by the

[92] Exh. PG&E-02 at 2-3, 2-10.

Commission's Energy Division. AECA believed that using the MPB figure would allow for consistent calculations across rate proceedings, including the Energy Resource Recovery Account (ERRA) proceeding.[93]

PG&E's rebuttal testimony indicated that they agreed in principle with the concept of a REC adder, stating that "PG&E agrees that incremental load in the test year (2021) increases PG&E's RPS requirement, irrespective of whether PG&E has enough RPS generation and/or [RECs] to meet the SB 100 mandate in 2021; and the same applies in 2025. Therefore, the marginal cost to procure (or not sell) RECs should be included in MEC."[94]

However, PG&E disagreed with the manner in which AECA calculated the REC adder. PG&E accused AECA of using an "out-of-date (i.e., incorrect) MPB" and asserted that "AECA [failed] to multiply the MPB REC market price by the RPS percentage in the test year."[95]

PG&E asserted that multiplying the MPB REC market price by the RPS percentage was necessary as SB 100 only requires 35.8 percent of load in 2021 (and 47 percent of load in 2025) to be met with RPS-eligible generation or RECs. Therefore, PG&E argued, "each [kilowatt-hour (kWh)] of load in 2021 requires the purchase, or lessens the potential sale, of 0.358 kWh of RECs" and that AECA overestimated "the impact of RPS purchases on MECs by failing to multiply the MPB REC price by 35.8 percent."[96]

PG&E's estimated REC adder in 2021 is $0.00519/kWh, based on the estimated 2021 REC value in the MPB multiplied by the RPS requirement for

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[93] Exh. AECA-01 at 28.

[94] Exh. PG&E-07 at 2-8.

[95] Exh. PG&E-07 at 2-8.

[96] Exh. PG&E-07 at 2-9.

2021. PG&E argued that "[b]ecause the REC price has not fluctuated much over the past five years, PG&E assumes that the REC price will be the same in 2025 as it is in 2021 (in nominal dollars), resulting in a REC adder of… $0.00681/kWh in 2025."[97]

PG&E requested that the Commission find that a non-time-differentiated REC adder equal to the most recent forecasted REC price for the test year times the RPS percentage in that year should be applied to MEC.[98] AECA argued against this proposal in briefs, asserting that the MPB used to calculate the REC adder used should be temporally consistent with the other calculations used by PG&E to set MEC. Therefore, they recommended that the MBP information used to calculate REC adder value be consistent with the moment when PG&E filed its GRC testimony in July 2020.[99]

The only party to de facto argue against the REC adder was CLECA, who recommended that a REC adder be set to zero given that PG&E is expected to meet their RPS requirement for several years into the future. However, PG&E rebutted CLECA's argument by pointing out that "PG&E is selling RECs to the CCAs whose RPS resources are insufficient to meet the required level."[100] Any excess RPS resources that PG&E may have at its disposal are therefore not guaranteed to apply to marginal energy purchases that it may make in the future.

It is logical to apply a REC adder to PG&E's calculated MEC, given that each marginal purchase of energy may involve the purchase of additional RPS-

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[97] Exh. PG&E-07 at 2-10.

[98] Exh. PG&E-07 at 2-11.

[99] AECA RB at 5.

[100] PG&E OB at 43.

compliant energy. This decision finds that it is reasonable to require the use of a non-time-differentiated REC adder equal to a REC value times the RPS percentage in a given year. The primary litigated question is how to calculate the REC value to be used in calculating the REC adder. Parties disagreed on the appropriate source of price data, with PG&E preferring to use MPB data updated in 2021 while AECA sought to require the use of MPB data that was temporally aligned with PG&E's other MEC-related data from 2020.

This decision notes AECA's concern, and agrees that it is reasonable to seek temporal consistency in PG&E's MEC calculations. Therefore, given that PG&E's overall MEC calculations are based on a CAISO market price forecast created in April 2020, it is appropriate for PG&E to use the MPB used in PG&E's 2021 ERRA proceeding as set forth in PG&E's ERRA testimony served in July 2020 to calculate the REC value. Per AECA's brief, the REC value in that testimony was $17.35/MW-hour.[101] PG&E shall use this REC value when calculating the REC adder value to be applied during this GRC cycle. This REC value and REC adder methodology may be revisited in PG&E's next GRC Phase 2 proceeding.

3.1.2. Ancillary Services Adder

TURN largely agreed with PG&E's method of calculating MEC, but sought to include a 1.7 percent adder to many of the MEC values to account for the cost of ancillary services.[102] PG&E disapproved of TURN's suggestion. PG&E

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[101] AECA RB at 5. This should lead to a REC adder value of $0.00621/kWh ($17.35/1000 * 0.358).

[102] Exh. TURN-01 at 31-32. The adder is meant to account for the incremental cost to load of ancillary services such as regulation and spinning reserve, which the CAISO procures and passes on to load serving entities.

reasoned that ancillary services costs do not vary in line with load[103] and "are likely to drop starting in 2021, so TURN's proposed adder would distort MECs, instead of making them more closely match PG&E's marginal costs."[104] PG&E asserted that ancillary services costs would be expected to drop in the near future due to the performance on ancillary service tasks by energy storage systems.

PG&E's arguments on this point are persuasive. Adopting TURN's proposal would have the potential to distort PG&E's MEC calculations rather than enhancing their accuracy primarily due to the fact that ancillary services costs do not vary linearly with load. It would be unreasonable to apply a 1.7 percent adder to MECs given that lack of correlation. However, PG&E proposed to reexamine this issue in its next GRC Phase 2 proceeding to determine if energy storage is having an effect on the price of ancillary services. The parties are encouraged to do so in order to provide a more informed basis for a Commission decision on this point in the future.

3.2. Marginal Generation Capacity Costs

Marginal generation capacity costs (MGCC) reflect changes in generation capacity costs that are associated with usage coincident with peak demand. This generation capacity cost does not include the cost of energy itself, as those costs are captured by the MEC calculation. Instead, MGCC looks at the cost of the physical capability to generate electricity, which usually consists of costs to construct a new power plant and the operation and maintenance costs associated with it. MGCC are expressed in dollars per kilowatt-year ($/kW-year) and are calculated for three voltage levels.

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[103] PG&E noted that of the three primary ancillary services, two trended with load and the third had prices that moved opposite to prices for marginal energy. (Exh. PG&E-07 at 2-14 to 2-15.)

[104] Exh. PG&E-07 at 2-13.

PG&E proposed to break MGCC into three components: 1) generic, or "system" capacity (in which system-wide peak demand is considered), 2) local capacity (in which the peak demand is measured at the local level), and 3) flexible, or "flex" capacity (in which the demand is measured relative to the three-hour positive ramp in system net load).[105]

As part of its MGCC calculations PG&E estimated different costs of service for NEM and non-NEM customer sub-groups, and requested Commission approval of the methodology and results presented in its testimony.

3.2.1. System MGCC

For system MGCC, PG&E estimated the system capacity component of its 2021 MGCC by levelizing six years of forecasted annual avoided capacity costs from January 1, 2021 through December 31, 2026. For the 2025 MGCC, PG&E used the levelized avoided capacity costs from January 1, 2025 through December 31, 2030. PG&E utilized this six-year averaging methodology in deference to Commission policy supporting that approach.

PG&E exclusively relied on long-run avoided capacity costs to estimate its MGCC. In other words, PG&E believes that MGCC for the system should be based on the costs to construct and operate the cheapest new power plant.[106] For 2021-2026, PG&E expected this kind of power plant to be front-of-the-meter four-hour lithium-ion energy storage (hereinafter energy storage) and calculated the MGCC based on the costs to construct and operate such a facility[107] to meet

[105] Exh. PG&E-02 at 2-2.

[106] As opposed to the costs to continue operating the most expensive existing power plant, which would be expressed as short-run avoided capacity costs.

[107] PG&E used the StorageVET model developed by the Electric Power Research Institute to help develop these cost estimates. The model is open-source and can be publicly accessed. (Exh. PG&E-02 at 2-43 and 2-44.)

marginal demand during peak times. PG&E reasoned that pursuant to state law and policy "new natural gas generation is unlikely to be built in California in the future, even if its net cost were lower than that of [energy storage]. If new natural gas generation is unlikely to be built, it would be inappropriate to use a [natural gas plant] as the marginal new-build unit in California."[108]

PG&E asserted that it was appropriate to rely exclusively on long-run avoided capacity costs as modeling from the Commission's 2019-2020 Integrated Resource Plan (IRP) Reference System Plan (RSP) adopted by D.20-03-028 and that the findings of D.19-11-016 indicated a need for new procurement of capacity starting in 2021.[109] PG&E also argued that its methodology aligned with the Commission's guidance in its recent decision concerning the use IRP inputs.[110]

Ultimately, and after several revisions that PG&E claimed were reasonable in light of changes to Commission guidance and legitimate errors pointed out by other parties,[111] PG&E calculated levelized[112] 2021-2026 MGCC values of $102.66/kW-year for transmission level customers, $105.68/kW-year for primary distribution level customers, and $112.01/kW-year for secondary distribution

[108] Exh. PG&E-02 at 2-55. PG&E noted that other technologies, such as long-duration energy storage (*e.g.*, pumped storage) "could also start to provide capacity by the late 2020s" but were not modeled for the purpose of setting MGCC in this proceeding. (Exh. PG&E-02 at 2-57, fn 90.)

[109] Exh. PG&E-02 at 2-4.

[110] PG&E OB at 45, citing D.20-04-010 at 30-31.

[111] *See* PG&E OB at 46-47 for a list of corrections and modifications.

[112] Levelized in the sense that PG&E levelized the annual real economic carrying costs of the total fixed costs of a new marginal generation resource net of energy revenues over the assumed asset life of the resource. (Exh. PG&E-02 at 2-45.) For an energy storage resource, energy revenues are equal to proceeds from ancillary service provision and energy arbitrage. (Exh. PG&E-02 at 2-47.)

level customers.[113] [114] These figures include a 15 percent adder for the Commission-mandated planning reserve margin.

3.2.2. Local MGCC

PG&E testified that, based on the Commission's 2018 Resource Adequacy report, there is no premium for local capacity in PG&E's service territory and therefore local capacity cost is the same as the overall average capacity cost for the years 2021-2022. As a result, PG&E does not calculate a local MGCC that is distinct from system MGCC.[115] This position is undisputed and this decision therefore accepts that local MGCC should be set to zero.

3.2.3. Flex MGCC

Flex MGCC represent the costs for generation capacity needed to meet the steepest predicted ramp up in load, rather than the peak load itself. PG&E's estimate of least-cost flex MGCC was "curtailment of contracted solar resources during the first hour of the maximum ramp on Flex need days."[116] In other words, the cheapest way to meet flex capacity requirements is to turn off solar during the maximum ramp up period. PG&E therefore sets its flex MGCC requirement at zero. This position is undisputed and this decision therefore accepts that flex MGCC should be set to zero.

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[113] Exh. PG&E-02 at 2-9, Table 2-3. PG&E also calculated 2025-2030 levelized MGCC values, but these were used to validate TOU periods and not used to establish marginal cost responsibilities for the purpose of revenue allocation and rate design.

[114] Different marginal costs for each voltage level are created by starting with a transmission level MGCC and then multiplying by line loss factors for primary and secondary distribution customers. (Exh. PG&E-02 at 2-58.)

[115] Exh. PG&E-02 at 2-5.

[116] Exh. PG&E-02 at 2-6.

3.3. Calculating the System MGCC

Parties differed on several elements involved in the calculation of system MGCC. Each of these disputed elements are discussed below. Undisputed elements of the MGCC calculation are reviewed as well, and finally an MGCC value is calculated and approved.

3.3.1. Whither Lithium Ion

PG&E, TURN, and CLECA supported the use of energy storage to calculate MGCC, although TURN and CLECA derived different MGCC values for energy storage. PG&E and TURN agreed that a "four-hour" energy storage system should be used to calculate MGCC, while CLECA initially argued that a "six-hour" energy storage system was a better resource to use for the calculation.[117] [118] SEIA supported PG&E's used of a four-hour energy storage system to calculate MGCC, but disputed some of the inputs used by PG&E in the calculation.[119]

EPUC and FEA proposed the inclusion of solar generation costs when figuring the cost of energy storage as a capacity resource. They argued that an energy storage system should be coupled with a generator to charge and discharge to the grid, making it necessary to include the solar generation costs.[120]

AECA advised caution when considering whether to adopt energy storage as an MGCC resource and wished to see the Commission adopt a flexible

[117] "Four-hour" and "six-hour" generally refer to the number of hours the energy storage system can discharge at its maximum rated capacity.

[118] Exh. CLECA-01 at 26-28; Exh. CLECA-03 at 25-26 (utilizing a four-hour energy storage system in its calculations).

[119] SEIA OB at 4, also proposing a alternative basis for the MGCC using an IRP capacity "shadow price" for 2021.

[120] Exh. EPUC-01 at 6-7; Exh. FEA-01 at 15, 18.

position without committing to energy storage at this time. AECA recommended adopting a resource adequacy figure based on a market price benchmark methodology to calculate the MGCC.

Cal Advocates recommended basing the MGCC on the lowest cost available resource for 2021-2026, which Cal Advocates believed would be either the 2021 Power Charge Indifference Adjustment (PCIA) MPB, or the cost of energy storage depending on the year. Cal Advocates recommended using the PCIA MPB due to an apparent lack of publicly available marginal resource adequacy cost information, but conceded that PG&E or TURN's energy storage-based MGCC values would be acceptable.[121]

This decision finds that it is reasonable to adopt energy storage as the basis for calculating system-level MGCC, as recommended by PG&E, TURN, and CLECA. PG&E's reasoning on this point is sound. As a matter of state policy, it is unlikely that substantial investments in new natural gas combustion turbine (CT) generation will be made in California in the near future, even if its net cost were lower than that of energy storage. Given that substantial amounts of new CT are unlikely to be built in the near future, it would be inappropriate to use a CT plant as the basis for a system-level MGCC calculation. In deference to AECA's concerns, this decision should not be read as implying that energy storage is the Commission's preferred marginal generation capacity resource for time immemorial. Based on the record in this proceeding, it is most appropriate to select energy storage *at this time* simply for the purpose of calculating PG&E's system-level MGCC in the context of this proceeding.

[121] Cal Advocates OB at 10-11.

The argument of some other parties that electricity generation capacity costs should be included in the calculation of the marginal capacity cost of energy storage (either as a paired solar resource or not) is unpersuasive. PG&E's MGCC calculation based on energy storage already accounts for the cost – both in supply and capacity – of supplying electricity to the battery to be discharged later, just as historic MGCC CT calculations include the price of fuel for the CT generator.[122] As PG&E testified:

> The standalone batteries that PG&E assumes are the marginal capacity resource charge from the grid and pay the CAISO based on the cleared energy prices, just as they discharge to the grid and receive cleared CAISO energy prices. The charging energy can come from anywhere in the CAISO, or even outside (e.g., based on the Energy Imbalance Market instituted in 2014).[123]

PG&E includes the cost of electricity used by the battery in the MGCC calculation through its use of the Energy Gross Margin (EGM) variable, which is "the expected market revenue from energy and [ancillary services] **net of variable cost**."[124] Requiring the cost of electricity generation capacity to be included in the calculation would therefore amount to double-counting the cost of supplying the energy storage unit with electricity.

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[122] PG&E OB at 68.

[123] Exh. PG&E-07 at 2-31.

[124] Exh. PG&E-07 at 2-44 (emphasis added). The "variable costs" referred to by PG&E are the costs of supplying electricity to the energy storage device, which includes a capacity element given that these are market prices that – presumably – allow the generator to recover all relevant costs, including the capacity to produce the electricity.

Therefore, it is reasonable to use a stand-alone, four-hour energy storage system as the particular capacity resource to use in calculating the MGCC for PG&E in this proceeding.[125]

3.3.2. Test Year or Six-Year Average?

Parties differed on whether to use an estimated cost of energy storage based on a test year (*i.e.*, 2021), or based on a six-year average (*i.e.*, 2021-2026). PG&E sought to use a six-year average while SEIA, FEA, and EPUC proposed to use only the avoided capacity cost in the test year (2021) to calculate MGCC.[126] CLECA proposed the use of a three-year average.[127]

Cal Advocates asserted that the new capacity required by PG&E is needed to meet peak demand starting in 2021 is based on system reliability needs, and is not related to expected increases in peak demand. They argued that because MGCC should be based on capacity additions caused by change in customer load, PG&E's proposed capacity additions should not be used to calculate MGCC as the additions are caused by policy and "operational factors" not related to load growth.[128] Cal Advocates reasoned that recent Commission directives to secure additional resources are driven by region-wide supply constraints, not by

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[125] It is unclear if CLECA has abandoned its argument that a six-hour energy storage system should be used for MGCC. However, even if it has not, TURN's argument that a six-hour system "is not supported by the actual [resource adequacy] requirements established by the Commission or the California ISO (CAISO) [and that] PG&E currently satisfies its [resource adequacy] obligations with battery storage units that are rated based on a 4-hour discharge period" is persuasive. (TURN OB at 37.) A four-hour system should be used to calculate MGCC.

[126] *See, e.g.*, SEIA OB at 8-9.

[127] CLECA RB at 13.

[128] Exh. Cal Advocates-01 at 3-3 ("[c]ustomers have little or no control over the Commission's or the utility's environmental policies or operations, but they do have control over their own load. Thus, MGCC must be defined based on changes in cost caused by changes in load").

changes in peak customer demand, and therefore the additional procurement should not contribute to MGCC.[129]

In contrast, SBUA, FEA, EPUC, and SEIA argued that there is a need for new generation capacity. They reasoned that the definition of marginal cost does not depend on where the need comes from, and conclude that, therefore, the MGCC should be calculated based on the cost of building new resources. TURN did not weigh in on the question of needed capacity directly, but concurred with PG&E's position that when new generation capacity is needed, the appropriate marginal costs are based on the maximum of 1) new capacity cost net of energy revenue, and 2) fixed O&M cost net of energy revenue for an existing combined cycle generator. CLECA argued that generation capacity costs should almost always be based on new capacity costs because such costs are lumpy and new capacity cannot be delivered "just in time."

PG&E argued that the Commission's mandated capacity procurements in D.19-11-016 and adoption of the November 2019 Reference System Portfolio in the IRP proceeding requires PG&E to secure new capacity starting in 2021. PG&E further argued that its six-year approach was consistent with long-standing Commission precedent dating back to 1989.[130] PG&E opined that it would be inappropriate to change the six-year averaging approach as recommended by SEIA, FEA, and EPUC given that the test year costs for new capacity would be included in six-year averages in any event.

There is no dispute that PG&E will procure additional generation capacity between now and 2026. Cal Advocates' argument that this procurement should

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[129] Exh. Cal Advocates-01 at 3-5.

[130] PG&E OB at 58.

not contribute to MGCC is unpersuasive as it amounts to hair-splitting. Even if Commission directives to procure additional generation capacity are driven by region-wide generation shortages rather than customer demand, the underlying customer demand still drives the need to address region-wide generation shortages. If customer demand were to suddenly drop 50 percent during peak periods, then the generation capacity shortage that concerns the Commission would likely disappear. As customers are still in ultimate control of the shape of PG&E's demand, the creation of a marginal price signal based on the procurement required by the Commission remains appropriate.

Similarly, the sole use of test year cost data to generate an MGCC figure is inconsistent with Commission precedent and may send an inaccurate price signal. SEIA argued that the Commission precedent in this area is stale given the changes to the electricity generation marketplace since 1997, but SEIA does not explain why those changes should impact the Commission's previous determination that a six-year average was appropriate.[131] If, for example, 2021 energy storage costs were found to be unusually high or low, then the MGCC signal would be inaccurate. The use of six-year average helps to level out annual fluctuations in prices and therefore is a superior basis for calculating MGCC.

For these reasons, this decision adopts the six-year average basis for calculating MGCC and rejects the approach proposed by Cal Advocates to use a levelized cost of capacity using bilateral contract prices over 2021-2026, as well as the test year approach advocated by other parties.[132] In deference to the concerns of SEIA and other parties regarding the long-term impact of the cost

[131] SEIA OB at 9.

[132] For example, SEIA's recommendation to use the 2021 IRP shadow price for marginal capacity.

determinations made in this proceeding,[133] this decision notes that its approval of an MGCC using a six-year average is only for use during this GRC cycle. During PG&E's next GRC 2 proceeding this issue may be addressed again and the use of a new MGCC based on timely cost data may be considered.

3.3.3. Short-run vs. Long-run Costs for Test Year 2021

While this decision holds that a six-year average of energy storage costs should be used in generating PG&E's MGCC, the parties disputed exactly how to calculate the 2021 price for energy storage to be used in the six-year average.

While PG&E sought to use long-run costs for test year 2021, Cal Advocates, CFBF, and AECA argued that the test year 2021 component of MGCC should be calculated based on short-run costs for resource adequacy capacity paid to existing resources.[134] PG&E argued that it is appropriate to use long-run costs for the test year 2021 figure given that new capacity must be built now to deal with anticipated needs for additional generation capacity in the long-run.[135] As long-run costs begin immediately, PG&E argued that long run costs should be used for the 2021 cost figure.[136] Several parties including SBUA, SEIA, FEA, and TURN, supported PG&E's position.[137]

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[133] SEIA OB at 9 ("the Commission should limit its determination to the period covered by this GRC cycle (2021-2023), allowing it to reassess the storage market and associated costs in PG&E's next GRC Phase 2 proceeding").

[134] Exh. Cal Advocates-01 at 3-3; Exh. CFBF-01 at 14; Exh. AECA-01 at 28-29.

[135] PG&E OB at 59, claiming that the results from the IRP proceeding and Commission decisions in the Summer 2021 Reliability Order Instituting Rulemaking (R.20-11-003 or Reliability OIR) evidence such a need.

[136] PG&E OB at 59.

[137] PG&E OB at 60-62.

Many of the parties' arguments on this point echo the discussion reviewed above. Some parties, such as Cal Advocates, do not believe that long-term generation procurement is a function of anything other than policy mandates, and therefore do not believe a price signal based on unavoidable capacity procurement is justified. AECA does not wish to see the Commission select a particular technological resource at this time, and therefore favors a test year 2021 cost figure that is based on a market price benchmark of resource adequacy capacity.

This decision previously found that it is undisputed that PG&E will be required to procure additional generation capacity between now and 2026. This decision therefore concurs with PG&E's reasoning that the long-term costs that are incurred in 2021 should be used to generate the 2021 cost figures used in the six-year average MGCC calculation. Additionally, the use of long-run energy storage costs for the 2021 MGCC cost figure better aligns with the determination to use a six-year average of a certain resource (i.e., energy storage) rather than mixing costs from different forms of capacity (i.e., a blended average of resource adequacy and energy storage cost figures).

3.3.4. Capital Cost of Energy Storage

PG&E proposed to calculate the capital cost of an energy storage unit by using the cost assumptions from the 2019-2020 IRP dataset, which draws from public levelized cost of service (LCOS) reports by Lazard and the National Renewable Energy Laboratory (NREL). PG&E updated its initial cost data based on faster cost reductions from 2018 to 2019 calculated from the Lazard 5.0 LCOS report, as it provided newer data than was in the 2019-2020 IRP from the Lazard 4.0 report. PG&E's cost reduction trajectories assumed the same 43 percent overall reduction in capital costs between 2021 and 2026 used in the 2019-2020 IRP dataset.[138]

FEA and EPUC argued that PG&E's assumed battery capital cost reduction of 43 percent between 2021 and 2026 is unsupported and did not factor in inflation. In its direct testimony, CLECA criticized PG&E's exclusive reliance on Lazard cost projections and recommended that PG&E use NREL cost estimates.[139] SEIA urged the Commission to require PG&E to use updated NREL cost estimates from 2020, which PG&E apparently declined to consider when estimating capital costs.[140]

EPUC broadly criticized PG&E's use of the IRP modelling to support its estimate of the capital cost of energy storage. EPUC claimed that IRP products are not vetted through evidentiary hearing, and instead are based on a workshop-and-comment process. This process may also not correctly value long-run energy storage, according to EPUC, if unique contracts are used as inputs without regard as to the duration of those contracts.[141]

With respect to PG&E's forecasted declines in the cost of energy storage, CLECA suggested that an expected increase in demand for lithium-ion batteries will result in an increase in energy storage costs not anticipated by PG&E.[142] SEIA argued that PG&E's forecasted cost decline of 43 percent was too

[138] PG&E OB at 69.

[139] It appears this criticism is unfounded, as PG&E used cost inputs from the 2019-2020 IRP, which relied on both the Lazard and NREL sources. PG&E's cost inputs fall between the Lazard 5.0 capital costs and the 2019 NREL costs used by CLECA (*e.g.*, for the year 2019, the NREL study used a value of $1,448/kW, Lazard used a value of $1,386/kW, and PG&E used a value of $1,424/kW). (PG&E OB at 70.)

[140] SEIA OB at 7.

[141] EPUC RB at 6-7.

[142] CLECA OB at 23.

aggressive, and that at a minimum the Commission should consider that there is uncertainty regarding energy storge cost declines that are not reflected in PG&E's model.[143] However, TURN rebutted these arguments by pointing out that forecasts of energy storage capital costs are in flux, and as a result it is best to select PG&E's estimates as they represent a reasonable attempt to calculate capital costs in the midst of this uncertainty.[144]

CLECA's argument concerning market forces that may cause energy storage prices to increase (rather than decrease) is unpersuasive. As pointed out by PG&E in its brief, an increase in demand for lithium-ion batteries will incent the development of greater battery supply over time. The market will eventually find a price that effectively matches supply and demand, and the historic downward trends evidenced so far suggest that the price will decline over the near-term, rather than increase.

Because PG&E bases its energy storage cost of capital calculation on the dataset used in the IRP proceeding, with certain modifications,[145] PG&E's estimates are generally consistent with the Commission's approved process for long-term generation procurement planning. SEIA noted that, in spite of PG&E's claims, the IRP dataset is not required to be used to set PG&E's MGCC. Nonetheless, this decision holds that it is appropriate to use the dataset to help set PG&E's MGCC in this proceeding given that it has already been vetted by the Commission to help plan for long-term generation capacity. PG&E's modifications, consisting of updating initial cost data based on more recent research, were appropriate and are approved notwithstanding SEIA's entreaties

[143] SEIA OB at 7-8.

[144] Exh. TURN-02 at 24-25.

[145] PG&E OB at 69-71.

that other cost estimates be used. PG&E's cost calculations fall between NREL and Lazard estimates, and this supports a finding that PG&E's estimated capital costs are reasonable.

The arguments of several parties that PG&E's estimated 43 percent cost decline should be rejected as too aggressive are unpersuasive. This decision agrees with TURN that PG&E's forecasted 43 percent cost decline is a reasonable estimate given the substantial uncertainty that exists with respect to future energy storage costs. It is therefore reasonable to adopt PG&E's proposed estimates of the cost of capital for energy storage as it applies to the MGCC calculation in this proceeding. This decision takes note of the arguments concerning cost uncertainty raised by several parties[146] and observes that there is uncertainty in the calculation of capital costs for energy storage systems into the future. The Commission expects that the capital cost calculations will be revisited in PG&E's next GRC Phase 2 proceeding to account for and address this uncertainty.

3.3.5. Financial Assumptions

PG&E made several financial assumptions when calculating the cost of an energy storage system in line with its use of the RECC methodology. These assumptions were:

- Inflation adjustments line with those used in the IRP RESOLVE model.
- The same debt cost and debt equity ratio used in the 2019-2020 IRP model.

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[146] *See, e.g.*, SEIA OB at 8.

- An annual return on equity (ROE) input based on the IRP RESOLVE model.[147]
- A weighted adjusted cost of capital (WACC) based on the 2019-2020 IRP model, adjusted using PG&E's most recent after-tax WACC when calculating the levelized 6-year MGCC from annual avoided capacity costs.
- Indirect imputation of taxes by subtracting energy gross margins from an energy storage system's capital costs.[148]

In general, PG&E asserted that using the IRP's assumptions were reasonable given that they reflect the actual structure of many energy storage contracts, including some recently signed by PG&E.

CLECA criticized PG&E's financial assumptions on several fronts. First, they argued that PG&E should have applied factors that would result in a financial payment that declines over time. CLECA also argued that the cost of taxes associated with energy gross margin has not actually been subtracted from the cost of capital. CLECA claimed that PG&E's financial assumptions in general were understated and should have been modified to account for the lower cost of debt currently being experienced at the market. CLECA also argued that the WACC figure used was too low given the risks faced by the developers of energy storage projects.[149]

PG&E asserted that CLECA was simply mistaken concerning the tax assumptions built into the EGM and IRP methodologies, and that the interest

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[147] TURN initially criticized PG&E's ROE number, but in subsequent testimony PG&E granted that it had made an error as pointed out by TURN and adjusted its ROE figures accordingly.

[148] PG&E OB at 71-72.

[149] CLECA OB at 27-28.

rate assumptions used by the IRP should also be used without modification to account for short-term variations in the price of debt reflected in the market.

This decision finds that PG&E's financial assumptions for the MGCC cost of capital calculation, with the exception of property tax inputs, are reasonable and should be approved. This is because PG&E based its assumptions on the IRP model already approved and utilized by the Commission in planning for future generation procurement. While CLECA broadly criticized PG&E's usage of IRP modeling and claimed that PG&E's reliance on the IRP assumptions was inappropriate,[150] this decision respectfully disagrees and finds that IRP assumptions are an appropriate basis for calculating the MGCC given their role in planning future generation capacity procurement by the Commission.

With respect to property taxes, CLECA's argument that the IRP dataset does not actually include a property tax element, in contrast to PG&E's claims, is provocative and indicates a material dispute on a factual issue.[151] It is not apparent from the record of this proceeding that the cost of property taxes have been appropriately included in PG&E's MGCC calculation. However, there is also a lack of record support for making a particular calculation for property taxes in this phase of the proceeding. For these reasons, it is necessary to consider the question of a "property tax adder" for the MGCC in a future phase of this proceeding. PG&E shall reserve final calculation of its MGCC until such time as an appropriate property tax adder is calculated in a later phase of this proceeding. PG&E is encouraged to work with interested parties to serve a

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[150] CLECA RB at 16-17.

[151] CLECA RB at 21-22.

stipulation on this matter in the final phase of this proceeding considering real-time pricing options for PG&E customers.

3.3.6. Energy Gross Margin

PG&E proposed to adjust the MGCC value assigned to energy storage by deducting the revenues the energy storage facility operator is expected to receive through sales of energy and ancillary services, net of variable costs.[152] In essence, the trading of energy at different times of the day could become a revenue stream for energy storage operators as energy is stored during low-cost hours and then redistributed to the grid during high-cost hours. PG&E reasoned that this source of potential revenue, referred to as EGM should be deducted from the cost of an energy storage system.

CLECA argued that as energy storage applications become more common, potentially equaling gigawatts of new battery capacity the coming years, the increased competition for energy arbitrage transactions among energy storage developers will flatten, rather than increase, market price differentials. CLECA reasoned that this makes PG&E's EGM revenue calculations for energy storage project operators too optimistic and therefore overvalued; however, CLECA agreed with PG&E that in principle EGM should be deducted from capital costs.[153]

FEA and EPUC took their argument further than CLECA and argued that EGM should not be subtracted from energy storage capital costs at all. FEA reasoned that any EGM should be considered profit and that PG&E should use any resale of energy from energy storage to serve its own native load. EPUC

[152] PG&E OB at 75.

[153] CLECA OB at 29-30.

likewise would not subtract EGM from energy storage capital costs, reasoning that EGM revenue is too uncertain to use in the MGCC calculation.

PG&E rejected each of these arguments. They first noted that FEA's recommendation that energy storage be discharged solely to serve PG&E customers was not actionable due to CAISO rules. Second, they argued that energy storage developers would likely not develop their projects at the capital costs advertised and used by PG&E as cost inputs if they did not incorporate the expect value of EGM into their project costs. Finally, PG&E reasoned that energy storage project developers must make some assumptions about the value of EGM when developing their project costs, and therefore it would not be reasonable to adopt EPUC's suggestion to set EGM to zero due to inherent uncertainty.[154]

PG&E's arguments on this point are persuasive, and PG&E's EGM calculations should be adopted. As with other elements of the capital cost of energy storage, there is admitted uncertainty with the inputs, but that uncertainty should not prevent a reasonable MGCC calculation.[155] PG&E's estimates of future EGM values reflect empirical observations of the behavior of energy storage as arbiters of energy resources across different hours of the day. CLECA's argument that EGM will decrease in the future at a greater rate than forecasted by PG&E as more energy storage comes online is speculative at this

[154] PG&E OB at 76.

[155] *See, e.g.,* CLECA RB at 18, citing "evidence that market participants may be becoming much less optimistic about future EGM levels, and would like to shift the risk away from themselves. It may also mean that they will expect higher capacity payments to offset anticipated loss of energy arbitrage revenue." To the extent future contracts for energy storage capacity reveal such a trend CLECA is encouraged to present that evidence in PG&E's next GRC Phase 2 proceeding.

time. If and when such EGM decreases are observed in the future, CLECA should raise those facts when PG&E's MGCC is considered anew.

3.3.7. Battery Lifetime and Costs for Augmentation and Variable Operations and Maintenance

PG&E proposed MGCC elements related to an energy storage system's 1) battery lifetime (*i.e.,* the useful life of a battery project), 2) augmentation cost (*i.e.,* the cost for periodic augmentation of battery cells to keep them operating within specifications), and 3) variable operations and maintenance (VOM) (*i.e.,* the variable cost of operations and maintenance). PG&E's ultimate proposal on these elements aligned with the assumptions used in the IRP, which assumes a 20-year lifetime for the energy storage system, a VOM value of zero, and a fixed 4.2 percent annual augmentation cost applied only to the "energy portion" of battery installation costs (*i.e.*, the battery cells and containers which scale with the total energy capacity in MWh, not the power electronics and any interconnection costs, which scale with power capacity in MW).[156]

CLECA objected to PG&E's proposed values. In particular, CLECA disputed PG&E's method of calculating VOM, asserting that it is too low, and thus underestimates battery augmentation costs. CLECA pointed out that the recent Lazard reports on energy storage costs reflected VOM values of $20/MWh and $14/MWh.[157]

PG&E argued that its values should be approved given that they are "fully aligned with the 2019-2020 IRP (and also with the proposed 2021 Avoided Cost Calculator (ACC) model, which draws from the IRP)" and are therefore consistent with Commission direction in D.17-01-006.

[156] PG&E OB at 78.

[157] CLECA OB at 28-29.

As with other elements of PG&E's MGCC calculation methodology, this decision finds PG&E's proposed battery lifetime, augmentation, and VOM calculations reasonable given that they are consistent with the Commission's approved IRP modelling process. PG&E shall use its calculated values in its MGCC calculation.

3.3.8. TURN Alternative Method

TURN proposed an alternative method of calculating energy storage-based MGCC, which addresses several of the MGCC elements already considered and disposed of. TURN argued that its MGCC values, based on a "publicly available fixed charge model developed by TURN's expert witness and used for over three decades in regulatory proceedings," should be used instead of PG&E's model. The major differences with TURN's methodology are that it assumes a 15-year battery life and does not include augmentation costs associated with a 20-year life.[158] TURN argued that the results of its model were "consistent with real-world data on current and future energy storage costs" and therefore should be approved by the Commission.[159]

Because the primary basis for adoption of PG&E's proposed MGCC calculation is the consistency of PG&E's methodology with the inputs and methods used in the Commission's IRP proceeding, this decision does not adopt TURN's methodology for calculating MGCC in the context of this proceeding.

3.3.9. CLECA Concern Regarding TOU Differentials

CLECA sought to alert the Commission to an important policy consequence resulting from PG&E's proposed MGCC calculation. CLECA stated

[158] TURN OB at 34.

[159] TURN OB at 35.

that PG&E's proposed calculation would "dramatically reduce the [MGCCs] relative to the amount that is currently reflected in rates will greatly reduce the cost-based TOU differentials reflected in rates. This would occur because the TOU differentials reflect the comparison between on-peak and off-peak rates where the on-peak rate is based on both the MGCC and the on-peak [MEC], while the off-peak rate is based only on the off-peak MEC. While the on-peak MEC is higher than the off-peak MEC, the difference is not large enough to account for the current TOU differential. Thus, dramatically reducing the MGCC reflected in rates will ultimately flatten rates across TOU periods."[160]

The Commission takes note of CLECA's concern and this decision holds that it is desirable for PG&E to maintain reasonable peak-to-off-peak TOU differentials that approach a true cost basis even if its MGCC calculation is approved. Attachments to Exhibit PG&E-49 reveal that the peak-to-off-peak generation rate differentials are not materially affected by the adoption of PG&E's MGCC calculations by this decision. For example, for Schedule B-19 (Secondary), the current peak summer demand charge of $14.61/kW is lowered to $13.65/kW using PG&E's MGCC calculation. And, contrary to CLECA's predicted adverse outcome, the current ratio of peak-to-off-peak generation energy charges of 1.57 is actually increased to 2.04 under PG&E's MGCC calculation.[161] These changes are not material enough to warrant rejection of PG&E's MGCC calculations, even as this decision continues to maintain that PG&E's TOU rates should have reasonable peak-to-off-peak TOU differentials that approach a true cost basis.

[160] CLECA OB at 2.

[161] The figures used are from "Scenario 2" as prepared by PG&E for Exhibit PG&E-49, Attachment 2.

3.3.10. Undisputed Elements of the MGCC Calculation

Certain elements of PG&E's MGCC calculation were undisputed by the parties. Those elements are summarized here for completeness.

With respect to the short-run avoided capacity cost figure, PG&E used the annual going-forward cost of an existing generation resource net of EGM. For existing resources, PG&E reasoned that the highest residual cost technology is considered the most at risk for retirement, and therefore should set the marginal capacity cost. PG&E assumed an existing, less efficiency, combined cycle natural gas plant was the higher cost marginal unit in years where existing units can meet capacity requirements. PG&E used public data sources short-run resource adequacy prices to calculate the short-run avoided capacity cost number. Given the lack of dispute on this issue, this decision finds that PG&E's short-run avoided capacity cost figure is reasonable.

PG&E's proposed energy and demand-related line loss factors were also uncontested. These factors account for the amount of marginal energy that must be generated to meet marginal customer demand, given that some of the generated energy is lost on the way to the customer. No party disputed PG&E's line loss factors, and therefore this decision approves PG&E's calculations, as used to create the 2021 MEC by voltage levels, shown in Exhibit PG&E-2A.

Finally, PG&E's calculation of MEC for the purpose of setting MGCC is undisputed by the parties.[162] This decision therefore accepts the MEC results for the purpose of setting the MGCC.

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[162] PG&E OB at 50.

3.3.11. Final MGCC Calculation

Given all of the above findings and approvals, this decision adopts PG&E's long-run avoided capacity cost of $102.53/kilowatt-year in 2021, and six-year discounted average MGCC in 2021 of $68.56/kilowatt-year for 2021-2026, subject to the inclusion of a property tax adder to be considered and approved by a Commission decision in a later phase of this proceeding.

4. Marginal Transmission Capacity Cost

PG&E requested that the Commission adopt its marginal transmission capacity cost (MTCC) estimate of $12.6 per kW per year.[163] PG&E determined this figure by taking the value of deferrable transmission projects and dividing that value by forecasted load growth, defining deferrable projects as those that could be deferred if electric demand growth in the area served by the project failed to materialize as projected over a 10-year study period. Projects that address greater than a 10 percent capacity deficiency are defined as non-deferrable. PG&E also requested that the Commission permit PG&E to use this MTCC estimate for setting marginal cost-based price floors under tariff E 31 and for use in other proceedings where an MTCC estimate may be needed.[164]

SEIA did not fault PG&E's basic formula for calculating MTCC; SEIA argued that the key variable in the formula – the value of deferable transmission projects – was not properly estimated by PG&E. SEIA claimed that PG&E's methodology for selecting deferrable transmission projects was opaque and not supported by the record.[165] SEIA argued that the 10-year demand projections

[163] PG&E RB at 40.

[164] Exh. PG&E-02 at 5-8 and 5-9.

[165] Per SEIA OB at 14, PG&E categorized six out of 73 of planned projects as deferrable, which equates to approximately $206 million out of about $2.8 to $3.5 billion in project costs of its forecasted 2019-2028 transmission investments.

relied upon by PG&E for determining deferrable projects were highly uncertain, and pointed out that previous, unexpected reductions in demand "precipitated CAISO decisions to cancel, delay, or downsize about $3 billion in planned transmission projects, mostly in PG&E's service territory, as part of the CAISO-approved transmission plans covering 2016 to 2019."[166] With respect to PG&E's proposed 10 percent threshold for determining deferability, SEIA asserted that PG&E did not present load forecast data "on the record that supports its assertion that only six projects address capacity deficiencies of 10 [percent] or less."[167]

Instead, SEIA recommended that the Commission assume that 27 percent of PG&E's transmission projects are deferrable, in accordance with a study provided in the record of this proceeding. SEIA claimed that the study revealed that 27 percent "of PG&E's transmission investments are capacity-related – *i.e.,* this is the fraction of transmission investments necessary to provide the capacity to meet customers' peak demands, and thus can be impacted by a change in customer demand during peak periods."[168] SEIA argued that the generally accepted practice of defining marginal costs supports the use of peak-related transmission investments as equivalent to deferrable transmission projects, as the MTCC should seek to capture peak-related demand that can be reduced by a customer. SEIA recommended that the Commission adopt an MTCC value of $52.45 per kW-year, by assuming that 27.26 percent of PG&E's 2021-2024 investments are capacity-related and are therefore marginal transmission costs.[169]

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[166] SEIA OB at 14.

[167] SEIA OB at 14-15.

[168] SEIA OB at 16.

[169] SEIA OB at 16.

PG&E replied to SEIA arguments by asserting that it reviewed each of its planned transmission projects for potential deferability and appropriately excluded projects that are designed to address reliability concerns, among others.[170] PG&E essentially argued that if a transmission project is related to reliability concerns or Commission mandates then it cannot be deferred, regardless of whether that reliability concern is tied to peak demand.[171] CLECA supported PG&E's arguments, stating that "not all capacity-related transmission is related to load growth, as SEIA implies."[172]

The Commission is unconvinced by PG&E's argument that reliability and capacity-related transmission projects should not be presumed to be tied to demand and load growth. In fact, it seems logical to assume, as SEIA does, that capacity-related projects are tied to some degree to demand and load growth given that reliability concerns may logically be tied to increases in peak customer demand.[173] It is notable that PG&E's own cost-based rate design for transmission costs as proposed in Exhibit PG&E-02 includes the 27 percent of projects that are capacity-related in peak and part-peak demand charges,[174] which means that

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[170] *See* SEIA RB at 8, showing that if PG&E considers that a planned transmission project will "improve system deficiency, such as those that reduce Local Capacity Adequacy Requirements or cost-effectively reduce customer outage time" then that project is automatically presumed to be non-deferrable without reference to the impact of customer peak demand on that "system deficiency."

[171] PG&E RB at 41.

[172] CLECA OB at 6.

[173] *See, e.g.*, extensive testimony from the parties related to MGCC and the need to procure additional generation capacity in the near future to ensure grid reliability in the face of increasing peak demand. It is logical to presume that marginal transmission investments seek to address the same reliability concerns as marginal generation capacity investments.

[174] Exh. PG&E-02 at 5-8, Table 5-4.

PG&E believed that a price signal for these costs should be based on expected peak and part-peak demands.[175]

For these reasons, it is reasonable to adopt SEIA's proposed MTCC of $52.45 per kW-year on the presumption that approximately 27 percent of PG&E's near-term planned transmission investments[176] are related to capacity needs and therefore will be impacted by customer reductions in peak demand in response to marginal cost signals.

4.1. Time-Differentiated Transmission Rate Proposal

In light of the substantial portion of PG&E's marginal transmission costs that may be affected by changes in peak demand, SEIA and SBUA recommended that the Commission advise PG&E to propose a rate design proposal at the Federal Energy Regulatory Commission (FERC) to time-differentiate its transmission rates.[177] They also suggested that the Commission could order its own Legal Division to intervene in PG&E's next transmission rate case at FERC for the purpose of advocating for a re-design PG&E's transmission rates such that the appropriate percentage of transmission costs are recovered in peak-related charges.[178]

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[175] Exh. PG&E-02 at 5-5 and 5-6 ("in accordance with the established principle of cost-causation, PG&E assigned the dollar amount of transmission capacity-related costs to be recovered through system-peak demand charges"). *See also* Exh. SEIA-01 at 20 ("PG&E's cost causation study proposes to allocate the 27 percent capacity-related portion of its transmission costs on a time-dependent basis, mostly to the peak period. This is a further indication that PG&E considers at least this portion of its transmission costs as dependent on changes in customer peak demands").

[176] As noted by SEIA, the percentage of *planned* transmission projects that PG&E estimates to be capacity-related is 27.19, ensuring that this MTCC figure is based on forward-looking data. (SEIA RB at 11.)

[177] SBUA RB at 2.

[178] SEIA OB at 17-18.

PG&E opposed these proposals, claiming that they exceed the scope of this proceeding and the jurisdiction of the Commission. PG&E did grant, however, that the Commission could itself propose revisions to PG&E's transmission rates in the next relevant FERC proceeding.[179]

As noted previously, this decision finds that a substantial proportion of PG&E's marginal transmission costs are related to peak demand. The record reflects that 27 percent of PG&E's transmission costs are capacity- or peak-related, whereas PG&E's transmission rates are flat volumetric rates for small customers and non-coincident demand charges for medium and large commercial and industrial customers.[180] This finding is based on PG&E's 2019 Electric Transmission Grid Expansion Plan, which appears in the record of this proceeding as ordered by the Commission in D.18-08-013. Thus, PG&E's retail customers are not receiving the appropriate time-differentiated price signals for the electric transmission services they receive. Even PG&E grants in its testimony that peak demand charges would be an appropriate avenue for recovery of 27 percent of PG&E's transmission costs.[181]

The Commission has long expressed a preference for marginal cost-based rate design and time-differentiated rates. It is well past time for PG&E to demonstrate the impacts of a prudent time-differentiated transmission rate on retail customers. The Commission therefore orders PG&E to submit a proposal for time-differentiated transmission rates to the Commission's Energy Division and parties in this proceeding for the purpose of allowing the Energy Division and other parties to examine the impact of time-differentiated transmission rates

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[179] PG&E RB at 49-50.

[180] SEIA RB at 17-18, fn 71.

[181] Exh. PG&E-02 at 5-5 and 5-6.

on retail customers. The Commission's Energy Division may choose to host workshops to further examine this issue in response to PG&E's proposal. The results of the analysis by the Commission's Energy Division should inform how the Commission will consider PG&E's future GRC Phase 2 applications. PG&E is ordered to submit its proposal to the Commission's Energy Division and serve a copy on parties to this proceeding within one year of the issue date of this decision.

5. Cost of Service: Delivered and Received Loads

As a part of its calculation of marginal generation and distribution cost responsibility for each customer class, PG&E proposed the use of distinct "delivered" and "received" loads. This is a new concept that is used for the first time in this proceeding. Historically, PG&E would only consider load and energy delivered to the customer classes in its marginal cost responsibility calculations. In this proceeding, PG&E recommended the use of received loads as well, *i.e.* those loads that are generated by the customer using distributed generation resources and received by PG&E's grid.[182] This section of the decision should be read as applying to the questions of whether to disaggregate "delivered" and "received" loads with respect to both generation and distribution marginal cost responsibilities.

PG&E's stated rationale for this new distinction is that customers generating their own electricity, usually from solar photovoltaic systems participating in NEM, are less likely to use the grid during low-cost hours in the middle of the day, and more likely to use the grid during high-cost hours in the

[182] It appears that PG&E is using data from NEM customers exclusively to calculate received loads. (Exh. PG&E-02 at 3-3 and 3-4.) This may be problematic in the future and is addressed later in this decision.

late afternoon and early evening *relative to other customers in the same class that are not NEM customers*. This means that NEM and non-NEM customers within the same class may have different cost of service profiles as NEM customers may concentrate more of their grid usage during high-priced hours.[183]

SEIA concurred with PG&E that it was appropriate to examine delivered and received loads when determining the cost to serve customer classes, but SEIA cautioned against using this method prospectively without further analysis and using this method to generate retail rate designs specific for customers utilizing certain technologies. Consequently, SEIA argued that the Commission should reject PG&E's request for the Commission to approve the proposed method of measuring the benefit of received loads for use in other future proceedings, and require further study of the impacts of received loads before doing so.[184]

Cal Advocates reviewed PG&E data responses on this topic and argued that, if significantly clustered, received loads can generate distribution net costs rather than benefits. Cal Advocates described evidence that 14 percent of PG&E's transformers (3,130 transformers total) have NEM received loads that make up 90-100 percent of the transformer's maximum load in a year, and that 5 percent of PG&E's transformers (1,886 total transformers) have NEM received loads that are greater than 100 percent of the transformer's maximum load in a year.[185] Cal Advocates asserted that if there are a significant number of NEM

[183] Exh. PG&E-02 at 1-2 and 1-3; 3-21 ("[o]n a net basis, NEM customers had a 40 percent higher average [marginal energy cost] than Non-NEM customers in 2017 and are forecasted to have 64.6 percent higher average [marginal energy cost] than Non-NEM customers in 2021").

[184] Exh. SEIA-01 at 22-28.

[185] Exh. Cal Advocates-01 at 5-10.

customers on a single transformer, this can cause the FLTs to switch from delivering energy to sending energy back to the grid, flipping the FLT into the "received" direction. Flipping an FLT into the received direction can, in their view, offset the benefits of received loads.[186]

Cal Advocates therefore agreed with PG&E's assertion that including received loads leads to more cost-based marginal cost calculations, and that "accurately estimated marginal costs are essential to efficient allocation of resources." Cal Advocates claimed that "as NEM penetration continues to grow, accurately estimating marginal costs will become more imperative to establishing fair revenue allocation."[187]

Cal Advocates asserted that the inclusion of received loads in PG&E's marginal cost analyses had a minimal impact of revenue allocation. For example, Cal Advocates found that the residential class (Schedule E1) would experience a small 0.06 percent increase in allocated loads (kW) by excluding received loads from the FLT methodology when compared to an FLT methodology that includes received loads.[188] Because of the minimal impact of the disaggregation of received loads on revenue allocation, Cal Advocates supported the use of received loads in this proceeding. However, Cal Advocates argued that the Commission should not set a precedent in this decision for the use of received loads going forward as "the long-term implications of including received load in revenue allocation, as NEM penetration increases, are unknown."[189]

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[186] Exh. Cal Advocates-01 at 5-8.

[187] Exh. Cal Advocates-01 at 5-7.

[188] Exh. Cal Advocates-01 at 5-5.

[189] Exh. Cal Advocates-01 at 5-8.

Furthermore, Cal Advocates noted that the results of PG&E's analysis of costs generated by NEM customers departs significantly from the methodology and findings of the Commission's ACC. Cal Advocates found that the two methods produced wildly different calculations for the benefits of NEM generation, and that the ACC methodology incorporated transmission and distribution benefits in addition to ancillary service revenues and greenhouse gas benefits whereas PG&E's method did not.[190]

To address the future unknown impact of using received loads, Cal Advocates recommended that the Commission direct PG&E to complete additional analysis to support the inclusion of received loads in subsequent proceedings that would "include, but not be limited to, scenarios that examine the potential impacts of increases in received loads on revenue allocation. These scenarios should be based on forecasts of NEM penetration growth. The Commission should require PG&E to provide this additional analysis in the 2023 GRC to support the inclusion of received loads in the PCAF and FLT methodologies."[191]

PG&E responded to the arguments of Cal Advocates and SEIA by asserting that it had already performed the additional analysis requested by Cal Advocates and that "the concerns raised by Cal Advocates and SEIA [were] baseless" as PG&E's proposed methodology assigned costs and benefits "appropriately for the net received load situations at system level."[192] Given this appropriateness, PG&E argued that it was reasonable for the Commission to

[190] Exh. Cal Advocates-01 at 5-15.

[191] Exh. Cal Advocates-01 at 5-8.

[192] Exh. PG&E-07 at 3-4.

adopt the proposed cost of service methodology in this proceeding and utilize in future proceedings (e.g., Rulemaking (R.) 20-08-020).

Exhibit PG&E-18 presented a joint stipulation between PG&E and Cal Advocates on these issues. In that exhibit, Cal Advocates agreed that PG&E's methodology was reasonable to adopt and apply in other proceedings, but given Cal Advocates' "concerns regarding the long-term implications of this methodology" only on a case-by-case basis.[193] Cal Advocates goes on to state that "[a]dditional analysis pertaining to the increase in NEM penetration, that is applicable to the entire system, is still needed."[194]

Given that the proposal to disaggregate delivered and received loads for the purpose of calculating cost of service is not directly opposed by any party for use in this proceeding, and given that this method creates more accurate calculations of cost of service for use in a GRC Phase 2 proceeding, this decision finds that it is reasonable to adopt PG&E's proposed cost of service methodology for use in this proceeding only. This decision expressly declines to authorize or forbid the use of PG&E's new cost of service methodology in any other Commission proceeding. The use of this methodology in any other Commission proceeding should be considered on the merits in those proceedings.

Similarly, and in order not to disturb the record currently being developed in other proceedings, this decision finds that the Commission's previously adopted methodology for calculating the potential benefits of NEM generation – the ACC – should not be viewed as diminished by the use of PG&E's new cost of service methodology in this proceeding.

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[193] Exh. PG&E-18 at 9.

[194] *Id*.

Finally, in light of the discomfort displayed by Cal Advocates and SEIA toward applying PG&E's methodology in the future without further study, this decision directs PG&E to complete additional analysis to support the inclusion of received loads in subsequent proceedings that includes, but is not limited to, scenarios that examine the potential impacts of increases in received loads on revenue allocation. These scenarios should be based on forecasts of NEM penetration growth, and should take into account other ways in which received loads may be generated in addition to NEM systems.[195] PG&E shall provide this additional analysis in its next GRC Phase 2 application to support the potential inclusion of received loads in its cost of service of methodology.

6. Revenue Allocation

As explained by Cal Advocates, the Commission has for decades used marginal cost calculations to allocate electric utility revenue requirements to a utility's customer classes. Marginal costs consist of generation capacity costs ($/kW), generation energy costs ($/kWh), customer access costs ($/customer hookup), and distribution capacity ($/kW) costs. "These marginal costs are the incremental cost to serve one additional kW or kWh of demand or an additional customer. The marginal cost revenues of each of these four components for each customer class are calculated by multiplying each class's per unit cost by their respective class level billing determinants."[196] The Commission prefers this marginal cost approach to revenue allocation as it promotes economic efficiency. If a class can collectively reduce its incremental cost to the utility, then it can reduce its overall responsibility for a utility's revenue requirement and, in turn,

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[195] *See* Exh. SEIA-01 at 23 ("it is important to designate customers who produce on-site power with a label that is not based on a particular compensation method").

[196] Exh. Cal Advocates-01 at 6-3.

its rates. The opposite is also true. If a class collectively imposes greater incremental cost on the utility, then it pays more in rates.

Consistent with Commission precedent, PG&E's application proposed to allocate revenue to its customer classes based on the class's contribution to PG&E's calculated marginal costs. That is to say, if the residential class was responsible for 39 percent of PG&E's distribution marginal costs, then the residential class would be allocated 39 percent of PG&E's marginal distribution revenue requirement. Because the collection of marginal revenue requirement would not sufficiently recover PG&E's embedded costs (i.e., its non-marginal costs), PG&E recommended utilizing the Equal Percent of Marginal Cost (EPMC) to scale up marginal cost responsibility to recover embedded costs. In this example, if the residential class was responsible for 39 percent of distribution marginal costs, then the residential class would also be responsible for 39 percent of PG&E's embedded distribution costs.[197] In this way, revenue allocation continues to track marginal cost responsibilities on a class-by-class basis. The EPMC method is applied separately to the distribution and generation functions, each of which have separate revenue requirements. The Commission enthusiastically embraced the EPMC method in principle in PG&E's prior GRC Phase 2 proceeding.[198]

PG&E also proposed to mitigate rate changes that would result from moving immediately to full-cost allocation by only moving one-sixth of the way to full-cost allocation each year, for six years, instead of applying caps and floors.

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[197] *See* Exh. Cal Advocates-01 at 6-3 for more detail ("[t]he EPMC scalar is calculated by dividing the revenue requirement by the summed marginal revenues for all classes").

[198] *See* D.18-08-013 at 19.

PG&E requested Commission approval for movement towards full-cost allocation during the first three years of that transition.

Cal Advocates also recommended using the EPMC method, but argued that its calculations of marginal costs should be used in place of PG&E's calculations to allocate revenue amongst PG&E's customer classes. Furthermore, and in contrast to PG&E, Cal Advocates recommended that the Commission should adopt caps and floors of +/-1.5 percent for changes to generation revenues and +/-2.5 percent for changes to distribution revenues to reduce fluctuation in customer class average rates. Adopting these caps and floors would limit the changes to customer class average rates that would result from the allocation of revenue pursuant to Cal Advocates' recommendations.

6.1. Caps and Floors

One of the issues litigated in this proceeding is whether caps and floors should be applied to revenue allocations that result from the application of any given marginal costs. PG&E's application asserted as a matter of economics and fairness that each class should be moved to its full marginal cost responsibility over a six-year period without mitigating that movement by using caps and floors. In contrast, Cal Advocates and other parties argued that a lack of caps and floors would move revenue allocations too quickly and cause customer discomfort with purported "dramatic rate changes" that would result.[199]

Cal Advocates supported its arguments for caps and floors by asserting that the COVID-19 pandemic and related stay-at-home orders increased residential electricity usage while also decreasing non-residential usage. If forecasted sales based on usage affected by COVID-19 were to be used for

[199] Exh. Cal Advocates-01 at 6-7.

revenue allocation, then potentially the residential class would be allocated more revenue responsibility than normal based on its usage. Cal Advocates argued that caps and floors should be used to mitigate against any potential bill impacts that might result, in addition to avoiding additional strains on customers facing greater unemployment rates as a result of COVID-19.[200]

6.2. Reallocation of Certain Distribution Costs

PG&E proposed to include a variety of utility costs and expenses in the distribution costs to be allocated to each customer class in line with that class's distribution cost responsibility. Some parties, such as Cal Advocates and TURN, objected to the inclusion of certain utility costs as distribution costs, and sought to have those certain utility costs reallocated as Public Purpose Program (PPP) costs or allocated on an equal-cents-per-kWh basis.

6.2.1. 2018 Catastrophic Event Memorandum Account (2018 CEMA) Costs

The Catastrophic Events Memorandum Account (CEMA) was approved in 1991. The purpose of this account is to allow utilities to recover the incremental costs incurred to repair, restore or replace facilities damaged during a disaster declared by the appropriate federal or state authorities. PG&E is recording costs associated with the repair of facilities and restoration of service associated with the 2018 Camp Fire in the CEMA. PG&E's revenue requirement for the 2018 CEMA is $294,348,586.

Cal Advocates argued that as a matter of fairness PG&E's 2018 CEMA costs should not be allocated to the various customer classes as distribution costs. They should instead be allocated based upon an equal-cents-per-kWh method because, according to Cal Advocates, "these costs are not marginal in nature;

[200] Exh. Cal Advocates-01 at 6-9.

they are directly related to the general welfare of residents within PG&E's territory," and "[t]his allocation method is consistent with past Commission decisions that approved equal-cents-per-kWh allocation for costs that benefit the public, such as the [California Alternate Rates for Energy (CARE)] surcharge."[201] TURN stated that Cal Advocates' proposal has merit.[202]

With respect to the 2018 Camp Fire restoration costs, Cal Advocates reasoned that "because these costs serve public interests by increasing operational safety while reducing service outages to all customer classes irrespective of the level of demand by class on the distribution system" the costs are not marginal and should not be allocated to various customer classes based on a class's marginal cost responsibility.[203] Ultimately, adopting Cal Advocates' proposal with respect to the 2018 CEMA costs would result in revenue allocations that reduce the residential class's total revenue allocation by ~ $40 million while increasing the total revenue allocation to large commercial customers by ~ $46 million.[204]

6.2.2. Hazardous Substance Mechanism (HSM) Costs

The Hazardous Substance Mechanism (HSM) is an account that provides a mechanism for allocating historical hazardous waste costs (such as from old-time coal to gas plants) among shareholders and ratepayers, including the allocation of insurance recoveries, if any. PG&E's revenue requirement for the HSM costs is $29,835,651.

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[201] Exh. Cal Advocates-01 at 6-13.

[202] Exh. TURN-01 at 33.

[203] Exh. Cal Advocates-01 at 6-14.

[204] Exh. Cal Advocates-01 at 6-16.

As with the 2018 CEMA costs, Cal Advocates argued that PG&E's HSM costs should not be allocated to the various customer classes as distribution costs. They should instead be allocated based upon an equal-cents-per-kWh method because, according to Cal Advocates, "these costs are not marginal in nature; they are directly related to the general welfare of residents within PG&E's territory," and "[t]his allocation method is consistent with past Commission decisions that approved equal-cents-per-kWh allocation for costs that benefit the public, such as the CARE surcharge."[205] Cal Advocates argued that "HSM costs produce significant public (e.g., environmental) benefits for all ratepayers and thus should not be based on each class' share of distribution marginal cost revenues."[206] TURN supported Cal Advocates' proposal to reallocate HSM costs.[207]

6.3. Costs for the Energy Program Investment Charge (EPIC), San Joaquin Valley Disadvantaged Community (SJV DAC) Pilot Program, and SJV DAC Data Gathering

PG&E proposed to allocate the cost of most non-CARE programs on an equal percent of total revenue (EPT), which consists of total revenue with generation imputed for Direct Access and Community Choice Aggregator (CCA) customers. These programs include, but are not limited to, the Energy Program Investment Charge (EPIC), the San Joaquin Valley Disadvantaged Community (SJV DAC) Pilot Program, and SJV DAC Data Gathering.

Cal Advocates argued that PG&E's costs for EPIC, the SJV DAC Pilot Program, and SJV DAC Data Gathering should be collected on an equal

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205 Exh. Cal Advocates-01 at 6-13.

206 *Id*.

207 Exh. TURN-01 at 36.

cents-per-kWh basis "because these programs provide social benefits to all ratepayers and this allocation method produces the most uniform allocation between small and large customers."[208]

With respect to EPIC in particular, Cal Advocates asserted that PG&E's proposed allocation failed to conform with Commission direction in D.11-12-035. In that decision, the Commission determined that EPIC costs should be allocated on an equal-cents-per-kWh basis instead of using the EPT method.[209]

With respect to costs related to the SJV DAC Pilot Program and SJV DAC Data Gathering, Cal Advocates noted that D.18-12-015 specifies that those costs shall be allocated based on "a rate design methodology approved for recovery of other non-CARE Public Purpose Program costs."[210] Cal Advocates argued that their proposed allocation method for those costs complied with that decision, while PG&E's proposal did not.

6.4. Demand Response Programs

TURN argued that other costs, other than those described by Cal Advocates, should be recovered as non-distribution costs subject to other cost recovery mechanisms. One of those costs is related to demand response (DR) programs. TURN reasoned that because DR essentially fulfills a generation capacity function (*i.e.*, the programs free up generation capacity during times of high grid demand), then the costs of DR programs should be recovered as embedded generation costs (with Direct Access customers contributing if they participate and benefit from DR programs).[211]

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[208] Exh. Cal Advocates-01 at 6-17.

[209] *Id.*

[210] *Id* citing D.18-12-015, OP 23.

[211] Exh. TURN-01 at 35.

Specifically, TURN proposed to subject the following DR programs to recovery through the generation EPMC scalar: base interruptible programs, other DR programs, statewide DR marketing, and Demand Response Expenditures Balancing Account (DREBA) incentives.[212]

6.5. Other Miscellaneous Costs, Including Energy Efficiency Shareholder Incentives

TURN also recommended that several other categories of costs be recovered outside of distribution. TURN argued that the Customer Energy Efficiency Incentive Account (CEEIA) should be allocated similarly to energy efficiency programs themselves through the PPP, while noting that the future of energy efficiency shareholder incentives is currently in doubt.[213]

Further, TURN believed that costs related to the Family Electric Rate Assistance (FERA) program should continue to be allocated to the residential class, even though PG&E did not propose to do so in this case.[214]

Finally, TURN proposed that approximately $21 million of "electric vehicle" costs should be allocated on an equal-cents-per-kWh basis.[215] TURN did not describe the specific "electric vehicle" costs referred to in its testimony.

6.6. Revenue Allocation Settlement

On April 8, 2021, PG&E served and filed a motion seeking adoption of a Revenue Allocation Supplemental Settlement Agreement (RA settlement). The motion claimed that the RA settlement resolved all contested and uncontested

[212] Exh. TURN-01 at 34, Table 11.

[213] Exh. TURN-01 at 35.

[214] Exh. TURN-01 at 36.

[215] Exh. TURN-01 at 36.

revenue allocation issues in the proceeding and that it was uncontested.[216] The contested issues resolved include:

- Whether to move allocation of revenues related to the DR, energy efficiency (EE) incentives, and electric vehicle (EV) programs from distribution to PPP.
- Whether to move revenues in the CEMA and HSM balancing accounts from Distribution to PPP and allocating by equal cents per kWh (equal cents).
- Whether to reallocate revenues for wildfire mitigation within distribution by using an equal cents allocator.
- How to treat Bundled PCIA revenue.
- Whether and how to mitigate revenue allocation changes by a transition plan and/or applying caps and floors.
- Whether to revise the Schedule Transitional Bundled Commodity Cost (TBCC).[217]

Each of these contested issues are addressed separately below.

6.6.1. Allocation of Demand Response, Energy Efficiency, and Electric Vehicle Costs

With respect to DR costs, the RA settlement proposed to continue collecting such costs through distribution rates but changing the allocation of those costs across classes to use the EPT method. The DR programs that would be affected by this change in allocation would include: DR generally, Statewide Marketing, Education and Outreach (ME&O) for DR, Base Interruptible Program (E-BIP) incentives, and DREBA Incentives.[218]

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[216] Motion to adopt RA settlement at 1.

[217] Motion to adopt RA settlement at 7.

[218] Motion to adopt RA settlement at 7-8.

For energy efficiency incentive costs, the RA settlement wished to move those costs from distribution rates to the PPP charge and allocate the costs by the EPT method. Doing so would harmonize the revenue allocation of energy efficiency incentive costs with the method general energy efficiency costs are allocated and the method that most non-CARE PPP revenues will be allocated.[219]

For electric vehicle costs, the RA settlement argued for consistency with current practice where such costs are paid for through distribution rates, using standard distribution cost allocators.[220]

6.6.2. Bundled PCIA Revenue

With respect to the treatment of bundled PCIA revenue, the RA settlement proposed that before allocating generation revenue, instead of including the PCIA revenue in the overall generation revenue requirement, PCIA revenue will be removed from each customer class's revenue at present rates based on the most recent vintage PCIA rates. Then, PG&E will use the adopted allocation for generation to allocate the PCIA revenue requirement to customer classes.

Allocating the bundled PCIA revenue in this manner assigns it in a manner consistent with the new generation allocators, which will be the same generation allocation factors that will be used to set PCIA values in the ERRA proceeding after the effective date of this decision.[221]

6.6.3. Mitigation of Changes to Rates Due to Revenue Allocation

The motion cited "the current economic climate" as justifying a measure of rate stability provided by the RA settlement through its use of caps on rate

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[219] Motion to adopt RA settlement at 8.

[220] Motion to adopt RA settlement at 8.

[221] Motion to adopt RA settlement at 11.

changes while arguing that the RA settlement still provides "some progress toward marginal cost."[222] The operative word appears to be "some" given that the motion also stated that RA settlement sought to "apply a cap without a floor and significantly limit the movement to whatever the Commission might decide about marginal costs" in this proceeding.[223] The actual cap proposed by the RA settlement is 1.5 percent, meaning that revenue allocations adopted by the RA settlement were only allowed to change 1.5 percent versus the revenue allocations currently in place. The RA settlement's proposed movement of each customer class toward the marginal costs adopted by this decision is capped at 10 percent.

The effect of this is to tightly constrain the impact of the marginal cost determinations in this decision on the average rates paid by customer. The table below illustrates the impact of the RA settlement's terms on average rates that may result from a range of marginal cost determinations.

[222] Motion to adopt RA settlement at 3.

[223] Motion to adopt RA settlement at 4.

Class Average Rate (bundled)	PG&E's marginal costs	TURN's marginal costs	CLECA's marginal costs	AECA's marginal costs
Residential	- 0.9 percent	- 0.7 percent	- 0.6 percent	- 0.7 percent
Small Commercial	0.7 percent	0.1 percent	1.2 percent	0.1 percent
Medium Commercial	- 0.6 percent	- 0.9 percent	- 0.7 percent	- 0.6 percent
Large Commercial	- 0.1 percent	0.1 percent	- 0.4 percent	0.1 percent
Streetlights	1.1 percent	1.5 percent	1.2 percent	1.5 percent
Standby	0.9 percent	1.1 percent	0.0 percent	1.1 percent
Agricultural	1.5 percent	1.5 percent	1.5 percent	0.9 percent
E20T	1.5 percent	1.5 percent	0.6 percent	1.1 percent
E20P	0.1 percent	0.8 percent	- 0.6 percent	0.6 percent
E20S	- 0.8 percent	- 0.1 percent	- 1.5 percent	- 0.3 percent

This table does not reflect the actual average rate changes that would result from the adoption of various marginal costs by this decision and the RA settlement. Those actual rate impacts are provided in Attachment 2 to Exhibit PG&E-49, utilizing the Scenario 2 marginal cost options.[224] Rather, the purpose of this table is to demonstrate how the RA settlement contains the impact of marginal cost findings, regardless of which findings are made. For example, while there is a wide spread between the marginal costs proposed by the parties, under the terms of the RA settlement the bundled residential class would see a mild average rate decrease regardless of which marginal costs are adopted by this decision.

[224] "Scenario 2," as defined by ALJ ruling, encompasses the marginal cost proposals of the parties largely adopted by this decision and the impact of RA settlement on rate changes. That scenario therefore most closely impacts the illustrative rate impacts that result from this decision.

6.6.4. Allocation of Wildfire Mitigation Costs

The RA settlement sought to address the question of how to allocate the costs associated with PG&E's wildfire mitigation efforts.[225] This includes allocation of the CEMA and HSM costs litigated by some of the parties. Eventually, the settling parties agreed on an approach where some portion of PG&E's ongoing wildfire mitigation costs would be allocated among customer classes using the EPT method rather than using distribution cost allocators for the entirety of the costs. Under the EPT method, costs are allocated proportionate to a class's total revenue allocation rather than simply their distribution revenue allocation. The amount of wildfire mitigation costs allocated using the EPT method is proposed to increase as the total aggregate amount of wildfire mitigation costs approved in other Commission proceedings increases.

The effect of this change in allocation is to decrease the amount of wildfire mitigation costs paid by certain customer classes that are more expensive to serve on the distribution network (e.g., the residential class) and increase the amount of wildfire mitigation costs paid by customer classes that are less expensive to serve on the distribution network (e.g., large commercial customers).

The parties to the RA settlement provided the following table illustrating how the allocation of wildfire mitigation costs between distribution and EPT methods changes as the total amount of costs increases.

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[225] The PG&E accounts used to determine "wildfire mitigation costs" are detailed below. The parties to the RA settlement claimed that it "leaves the revenue requirement associated with traditional vegetation management to be allocated functionally as distribution…". Costs associated with "enhanced vegetation management activities" in response to wildfire mitigation would be subject to the RA settlement's terms. (Exh. PG&E-44 at 6.)

Total Wildfire Mitigation Costs	Percent Allocated Using Distribution Factors	Percent Allocated Using EPT Method
$500 million	50	50
$700 million	39	61
$1 billion	31	69
$1.3 billion	27	73
$1.5 billion	25	75
$1.8 billion	23	77
$2 billion	22	78

The RA settlement included balances in the following PG&E accounts in its definition of wildfire mitigation costs:

- Fire Hazard Prevention Memorandum Account (FHPMA)[226]
- Fire Risk Mitigation Memorandum Account (FRMMA)[227]
- Wildfire Mitigation Plan Memorandum Account (WMPMA)
- CEMA (for Tree Mortality & Fire Risk Reduction activities)[228]
- Vegetation Management Balancing Account (VMBA) (for enhanced vegetation management activities)[229]
- Wildfire Mitigation Balancing Account (WMBA) (for Community Wildfire Safety Program and other expenditures)[230]
- Microgrids Memorandum Account (MGMA)[231]

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[226] Established pursuant to D.09-08-029, and tracks costs related to implementing fire safety standards promulgated by the Commission in R.08-11-005 and its successor rulemaking R.15-05-006. (Exh. PG&E-44 at 4.)

[227] Established pursuant to Senate Bill 901, via PG&E advice letter 5419-E. The Wildfire Mitigation Plan Memorandum account was authorized in D.19-05-038. (Exh. PG&E-44 at 4.)

[228] Tree Mortality and Fire Risk Reduction activities are recorded in the CEMA pursuant to Commission Resolution ESRB-4, issued in 2014. (Exh. PG&E-44 at 4.)

[229] Enhanced vegetation management costs are recorded in the account pursuant to D.20-12-005 (PG&E's test year 2020 GRC Phase 1 decision). (Exh. PG&E-44 at 4.)

[230] Authorized by D.20-12-005. (Exh. PG&E-44 at 4.)

[231] Originally established pursuant to D.20-06-017. The Commission provided authorization to track additional costs in this account in D.21-01-018. (Exh. PG&E-44 at 4.)

- Wildfire Mitigation costs that are securitized and recovered through bonds (as provided by Assembly Bill (AB) 1054).

Importantly, the RA settlement also includes a catch-all category of wildfire mitigation costs: "other revenue requirements, including balancing or memorandum accounts PG&E might establish, that are directly related to Wildfire Mitigation."[232] While it is not clear what future accounts might be included, the settling parties clarified that PG&E would have the discretion to designate such future accounts as including wildfire mitigation costs, and the RA settling parties would have the right to protest such designation.[233]

The parties to the RA settlement claimed that the Commission has not previously ruled on the appropriate allocation of the wildfire mitigation costs in the above-listed accounts, although they believe that in the absence of a specific ruling these costs were allocated according to standard distribution cost allocators.[234]

The RA settlement also has the effect of changing the litigation positions of PG&E and other parties in open proceedings considering the allocation of wildfire mitigation costs. There are three open wildfire mitigation cost proceedings that the parties to the RA settlement believe could be impacted by the RA settlement:

- A.20-09-019, the 2020 Wildfire Mitigation and Catastrophic Event (WMCE) proceeding. The parties to the RA settlement are participating in the ongoing litigation of the proceeding, and intend to update their

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[232] Motion to adopt RA settlement at 8-9.

[233] Exh. PG&E-44 at 8 (noting that the designation of any new accounts as containing wildfire mitigation costs subject to the allocations rules of the RA settlement would be outlined in PG&E's annual electric true-up process).

[234] Exh. PG&E-44 at 5.

testimony to reflect their agreement in the RA Settlement, such that, if the Commission adopts it in this decision, A.20-09-019 and this proceeding would be aligned with regard to revenue allocation.

- A.21-02-020, the proceeding for securitizing wildfire mitigation expenditures pursuant to AB 1054. PG&E expects to recommend the cost allocation approach proposed by the RA settlement in its Opening Brief in A.21-02-020. To the extent PG&E files a subsequent application for securitized AB 1054 costs, before its next GRC Phase 2 proceeding, PG&E would propose to use the wildfire mitigation cost allocation approach of the RA settlement to determine the allocation factors to be applied at the time of issuance of those subsequent bonds as well, after any potential securitization is approved.
- A.18-03-015, the proceeding considering CEMA costs in 2018. Because the RA Settlement allocates CEMA revenue requirements with wildfire mitigation and HSM costs, the allocations of distribution revenues from that proceeding would be affected by the RA settlement.[235]

Because the RA settlement impacts the litigated positions of the parties in the three above open proceedings, PG&E shall serve a notice on the service list of each proceeding informing the service list members of the impacts of the RA settlement and how it affects PG&E's litigated position. PG&E shall ensure through procedural communications that the assigned ALJ and Commissioner for each proceeding are aware of the impacts of the RA settlement on the litigated position of PG&E in the proceeding.

[235] Exh. PG&E-44 at 11.

6.6.5. Uncontested Issues

Finally, the RA settlement proposed adoption of certain uncontested issues related to revenue allocation. The RA settlement recommended that:

- For the Self-Generation Incentive Program (SGIP) and California Solar Initiative (CSI) programs:
  - move these revenues from Distribution to PPP,
  - for SGIP, maintain the existing Commission-approved allocation method, and
  - for CSI, use the EPT PPP allocation method.
- For the Tree Mortality program, designate revenues as PPP and use the Twelve Coincident Peak allocation method.
- For all non-CARE PPP programs not specifically given another allocation, allocate using the EPT method. Programs to use the EPT method include:
  - Procurement Energy Efficiency,
  - Energy Savings Assistance, and
  - Statewide Marketing, Education and Outreach.
- For the FERA program, allocate revenues only to the residential class.
- For the streetlight class, affirmation of the following revenue allocation issues settled among the parties to the Streetlight Rate Design settlement:
  - Present rate revenues for facilities charges will use present rate values when calculating percentage rate changes during the application of capping.
  - Capping of revenue allocation changes will apply to facilities charges for the City and County of San Francisco, which are calculated outside of the revenue model.

- Movement of 1/12th of the way to full cost for facilities charges.

6.6.6. Application of Article 12 of the Rules

The Commission has long favored the settlement of disputes. Article 12 of the Commission's Rules of Practice and Procedure (Rules) generally concerns settlements. Pursuant to Rule 12.1(d), 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 uncontested. The RA settlement is uncontested.

The RA settlement motion claimed that it was reasonable in light of the whole record as it represented a give-and-take among the parties after careful review of their litigated positions. The Comparison Exhibit attached to the motion also reveals that the terms of the RA settlement are compromise positions between the various positions taken by the parties in their testimony.[236] Given that the RA settlement adopts positions that represent compromises of litigated positions on the record, this decision finds that the RA settlement is reasonable in light of the whole record.

The RA settlement motion claimed that it was consistent with the law "as it complies with all applicable statutes and prior Commission decisions. These include Public Utilities Code Section 451, which requires that utility rates must be just and reasonable."[237] No party disputed that the RA settlement was consistent with the law and no inconsistency with the law is apparent. Therefore, this decision finds that the RA settlement is consistent with the law.

[236] Motion to adopt RA settlement at 16-17.

[237] Motion to adopt RA settlement at 17.

Finally, the RA settlement motion argued that it was in the public interest as it provides certainty for customers regarding their rates and their relative responsibility for certain of PG&E's costs, including wildfire mitigation costs. It also claimed that approval of the RA settlement "avoids the time, expense, and uncertainty associated with further litigating revenue allocation issues…".[238]

With respect to the arguments surrounding the public interest, this decision evaluates the rate and bill impacts of the RA settlement to determine if the impacts themselves are reasonable. Exhibit PG&E-49, Attachment 3, reveals the following average rate impacts that result from the adoption of the marginal costs approved by this decision and the RA settlement itself:

Customer Class	**Current Average Rate per kWh**	**Average Rate per kWh Due to Decision**	**Change in Average Rate Due to Decision**
Residential	\$0.22904	\$0.22769	- 0.6 percent
Small Commercial	\$0.26618	\$0.26652	0.1 percent
Medium Commercial	\$0.23722	\$0.23598	- 0.5 percent
E-19	\$0.20698	\$0.20731	0.2 percent
E-20	\$0.16644	\$0.16762	0.7 percent
Streetlights	\$0.31729	\$0.32205	1.5 percent
Standby	\$0.18041	\$0.18228	1.0 percent
Agriculture	\$0.25089	\$0.25465	1.5 percent

Given that the approved marginal costs and the RA settlement together lead to average rate impacts of less than one and a half percent in either a positive or negative direction for any given class, the rate impacts of the RA settlement are reasonable. This decision also finds that because all of PG&E's customers benefit from PG&E's efforts to mitigate the wildfire risk posed by its distribution network, and given that wildfire mitigation work is normatively

[238] Motion to adopt RA settlement at 18.

distinct from PG&E's ordinary distribution investments, it is desirable to reallocate PG&E's wildfire mitigation costs away from a strict distribution cost allocation and to more fairly distribute those costs to all of PG&E's customers, as proposed by the RA settlement. For all of these reasons, this decision finds that the RA settlement is in the public interest.

In light of the findings laid out previously, this decision finds that the RA settlement is reasonable in light of the whole record, complies with the law, and is in the public interest. Therefore, this decision approves the RA settlement and PG&E shall implement its provisions as soon as practicable.

With respect to the RA settlement's treatment of electric vehicle costs (using standard distribution cost allocators and collecting the costs through distribution rates), this decision makes clear that its approval of the RA settlement does not modify the allocation of electric vehicle-related costs determined in previous Commission decisions.[239]

7. Residential Rate Design

Several residential rate design issues were litigated in this proceeding and eventually subject to settlement: 1) the manner by which Schedule E-1 tier differentials should change in between GRC Phase 2 decisions, 2) Schedule E-TOU-C summer tier differentials, 3) the design of Schedule E-ELEC, and 4) baseline quantities. Remaining residential rate design issues were uncontested. This decision first considers the uncontested residential rate design issues, and then the residential rate design settlement.

[239] *See*, *e.g.*, D.21-07-028 at OP 2 ("[e]ach near-term priority program must recover authorized program funding through distribution rates allocated to customer classes on an equal cents per kWh basis").

7.1. Uncontested Residential Rate Design Issues

Several of PG&E's proposals on residential rate design issues were unopposed by the parties. These issues include: modifications to Schedule E-TOU-B, modifications to Schedule E-TOU-D, modifications to Schedule E-6, modifications to Schedule EV, modification to rules for changing TOU rates between GRC Phase 2 proceedings, and the elimination of the 50 percent discount on the delivery minimum bill amount for CARE, FERA and Medical Baseline customers.

7.1.1. Schedule E-TOU-B Modifications

PG&E proposed to increase the summer and winter generation peak-to-off-peak (POPP) differentials, respectively, by 2.0 cents each to 12.3 and 3.9 cents, effective January 1, 2022. PG&E claims that this modification "achieves the objective of gradually moving the POPP differentials closer to their marginal cost targets, while mitigating potential rate shock."[240] PG&E noted that Schedule E-TOU-B is already closed to new customers and will be eliminated for existing customers in October 2025.

No party contested PG&E's proposal, and this decision therefore finds that PG&E's proposed modifications to Schedule E-TOU-B are reasonable and should be adopted, given that they will gradually move E-TOU-B rates closer to the marginal cost to serve E-TOU-B customers while mitigating rate shock.

7.1.2. Schedule E-TOU-D Modifications

PG&E proposed that, for optional residential Schedule E-TOU-D, the summer generation and distribution POPP differentials, as well as the winter generation POPP differential, all be increased by 2.0 cents effective no earlier than January 1, 2023. For the winter distribution POPP, PG&E proposed to

[240] Exh. PG&E-03 at 3-28.

increase the differential by about 0.2 cents. PG&E reasoned that these changes to the POPP differentials were justified as they would "gradually bring all the POPP differentials much closer to (and, in the case of the winter distribution POPP differential, exactly to) their marginal cost targets—allowing customers to gradually adjust to stronger price incentives to shift load, while offering another differentiated TOU option."[241] According to the residential rate design settlement, these changes to E-TOU-D would result in a total differential of $0.13496 per kWh in the summer (consisting of a $0.10496 generation rate differential and a $0.03000 distribution rate differential), and a total differential of $0.03861 per kWh in the winter (consisting of a $0.03508 generation rate differential and a $0.00353 distribution rate differential).[242]

No party contested PG&E's proposal, and this decision therefore finds that PG&E's proposed modifications to Schedule E-TOU-D are reasonable and should be adopted, given that they will bring the schedule's POPPs closer to marginal cost targets and give customers a more refined economic signal to shift load.

7.1.3. Schedule E-6 Modifications

PG&E's Schedule E-6 is a legacy tiered TOU rate that has been closed to new customers since May 31, 2016 but remains open for legacy customers through 2022. Schedule E-6 has two tiers, along with three TOU periods in summer (peak, partial-peak, and off-peak) and two TOU periods in winter (partial-peak and off-peak). In D.15-11-013, the Commission approved a settlement that will phase out Schedule E-6 at the end of 2022.[243]

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[241] Exh. PG&E-03 at 3-29.

[242] Residential rate design settlement at 7.

[243] Exh. PG&E-03 at 3-30.

While the long and pioneering existence of Schedule E-6 is soon coming to an end, PG&E nevertheless proposed adjustments to the POPP differentials of the rate in order to move them closer to marginal cost. PG&E proposed to reduce the summer generation POPP differential by 2.0 cents to 15.3 cents and increase the summer generation part-peak versus off-peak differential by 2.0 cents to 7.0 cents, to bring both closer to their generation marginal cost target differentials. PG&E asserted that the current winter generation peak versus off-peak rate differential is 1.4 cents compared to the marginal generation cost differential of 5.37 cents, and therefore PG&E proposed a 2.0 cent increase to this differential, bringing it to 3.4 cents to better reflect marginal costs.[244]

On the distribution side, PG&E reasoned that "the current [POPP] differential of 24.3 cents vastly exceeds the 9.7 cent marginal cost target, so PG&E is proposing to decrease it by 2.0 cents to 22.3 cents." For the part-peak to off-peak summer distribution differential, PG&E proposed decreasing it by 1.1 cents to match the marginal cost target. Finally, for winter distribution rates, PG&E proposed to decrease the POPP differential by 2.0 cents to 1.9 cents to bring the differential closer to marginal cost. PG&E proposed that these changes take effect on January 1, 2022.[245]

According to the residential rate design settlement, the total differential between peak and off-peak in the summer would be $0.37656 per kWh (consisting of a $0.15311 generation rate differential and a $0.22345 distribution rate differential), the total differential between part-peak and off-peak in the summer would be $0.12013 per kWh (consisting of a $0.07018 generation rate

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[244] *Id.*

[245] Exh. PG&E-03 at 3-33.

differential and a \$0.04995 distribution rate differential), and the total differential between part-peak and off-peak in the winter would be \$0.05278 per kWh (consisting of a \$0.03380 generation rate differential and a \$0.01898 distribution rate differential).[246]

No party contested PG&E's proposal, and this decision therefore finds that PG&E's proposed modifications to Schedule E-6 are reasonable and should be adopted, given that they will bring the peak to off-peak and part-peak to off-peak price differentials closer to the marginal cost to serve E-6 customers.

7.1.4. Schedule EV Modifications

PG&E proposed adjustments to the TOU rate differentials for Schedule EV, effective January 1, 2022, but not for Schedule EV2. For Schedule EV, PG&E recommended reducing the summer POPP differentials for both generation and distribution by 2.0 cents, and the summer part-peak to off-peak price differentials by 2.0 cents as well for generation and distribution. PG&E reasoned that these adjustments were warranted to bring the Schedule EV TOU rate differentials "somewhat more in line with the smaller marginal cost differentials" actually observed by PG&E for the summer TOU periods applicable to the rate.[247]

With respect to Schedule EV's winter season rates, PG&E proposed to reduce the distribution POPP and part-peak to off-peak differentials by 2.0 cents each "to bring them somewhat closer to the much lower marginal cost differentials (which are very close to zero)."[248]

According to the residential rate design settlement, the total differential between peak and off-peak in the summer would be \$0.35666 per kWh

[246] Residential rate design settlement at 7.

[247] Exh. PG&E-03 at 3-35.

[248] Exh. PG&E-03 at 3-36.

(consisting of a $0.18985 generation rate differential and a $0.16681 distribution rate differential), the total differential between part-peak and off-peak in the summer would be $0.11255 per kWh (consisting of a $0.04638 generation rate differential and a $0.06617 distribution rate differential), the total differential between peak and off-peak in the winter would be $0.20374 per kWh (consisting of a $0.02485 generation rate differential and a $0.17889 distribution rate differential), and the total differential between part-peak and off-peak in the winter would be $0.07173 per kWh (consisting of a $0.07173 distribution rate differential).[249]

No party contested PG&E's proposal, and this decision therefore finds that PG&E's proposed modifications to Schedule EV are reasonable and should be adopted, given that they will bring the POPP and part-peak to off-peak price differentials closer to the marginal cost to serve EV customers.

7.1.5. Changing TOU Rates Between GRC Phase 2 Proceedings

PG&E proposed that, after the TOU rates are set in this proceeding, all subsequent changes to rates on residential TOU schedules, between this proceeding and PG&E's 2023 GRC Phase 2, be calculated on an equal-cents-per-kWh basis. PG&E asserts that "[d]oing so will maintain the marginal cost-based TOU rate differentials adopted in this proceeding" and that would be consistent with consistent with the rules for PG&E rate changes between GRCs approved by the Commission in D.18-08-013.[250]

No party contested PG&E's proposal, and this decision therefore finds that PG&E's proposal for modification of TOU rates in between GRC Phase 2

[249] Residential rate design settlement at 7-8.

[250] Exh. PG&E-03 at 3-37.

proceedings is reasonable and should be adopted, given that doing so will maintain the marginal cost-based differentials adopted by this decision and will comport with the rules adopted by the Commission in D.18-08-013.

7.1.6. Elimination of the 50 Percent CARE and FERA Discounts on the Delivery Minimum Bill Amount

PG&E proposed that the Commission revise its determination in D.15-07-001 that the Delivery Minimum Bill Amount (DMBA or minimum bill) should be $5 per month for CARE and FERA customers. Instead, PG&E recommended that there not be a separate minimum bill amount for CARE and FERA customers and that instead the CARE discount should be provided as a 35 percent discount for all CARE customers regardless of their usage level, and that the FERA discount should be provided as an 18 percent discount for all FERA customers regardless of their usage level.

PG&E argued that adopting its recommendation for CARE customers "would eliminate the variation in percentage bill discounts received by customers with varying usage levels and allow for a much simpler customer outreach message: 'Every CARE customer, regardless of rate schedule or usage, receives the identical 35 percent discount.' It would have minimal effects on CARE customer bills, at most increasing a bill by $1.50 for a customer with zero usage, while also resulting in bill decreases for the vast majority of CARE customers."[251]

PG&E asserted that its FERA recommendation "would eliminate the variation in percentage bill discounts received by FERA customers with varying usage levels and allow for a much simpler customer outreach message: 'Every

[251] Exh. PG&E-03 at 3-40.

FERA customer, regardless of rate schedule or usage, receives the identical 18 percent discount mandated by statute.' It, too, would have minimal effects on FERA customer bills, at most increasing a bill by $3.20 (for a customer with zero usage).

No party contested PG&E's proposals, and this decision therefore finds that PG&E's proposals for elimination of a separate minimum bill amount for CARE customers to facilitate the application of a single 35 percent discount and for elimination of a separate minimum bill amount for FERA customers to facilitate the application of a single 18 percent discount are reasonable and should be adopted. This finding is supported by the fact that PG&E's proposals are likely to simplify CARE and FERA outreach and lead to bill decreases for the vast majority of CARE customers (and minimal impacts for FERA customers).

7.1.7. Elimination of the Medical Baseline Minimum Bill Discount

Similar to its proposals for CARE and FERA minimum bill adjustments, PG&E proposed that the $5 minimum bill for medical baseline program participants be increased to $10, as will be the case for all other customers should PG&E's other proposals be adopted.

PG&E's rationale for its proposal is that medical baseline customers will receive their effective discount on a minimum bill by receiving additional baseline allocations and therefore will be able to consume additional kWh at the lower Tier 1 rate even if their minimum bill increases from $5 to $10. As a practical matter, PG&E claimed that its proposal "is unlikely to affect many Medical Baseline customers, since the DMBA only affects the bills of very low users and Medical Baseline customers typically are high users. Indeed, the whole rationale for providing such customers with additional baseline amounts is to mitigate the high bills they would otherwise face due to their medical needs causing their usage to increase into the upper tiers."[252]

No party contested PG&E's proposal, and this decision therefore finds that PG&E's proposal to increase the minimum bill for medical baseline customers to $10 is reasonable and should be adopted, given that it harmonizes the minimum bill amount across all of PG&E's residential rate schedules and is expected to have negligible bill impacts on medical baseline customers due to the relatively high usage exhibited by those customers.[253]

7.2. Residential Rate Design Settlement

On March 29, 2021, PG&E served and filed a motion to adopt a Residential Rate Design Supplemental Settlement Agreement (residential rate design settlement). The motion stated that the residential rate design settlement was uncontested, and that the following parties joined the settlement: PG&E, TURN, Cal Advocates, CforAT, WMA, Joint CCAs, NRDC, Sierra Club, SEIA, and CALSSA. The motion averred that the following issues were resolved by the residential rate design settlement:

- Tiered rate levels for Schedule E-1
- Schedule E-TOU-C peak versus off-peak price differentials
- Schedule E-ELEC design
- Baseline quantities
- Master meter discounts
- Timing and implementation of rate changes

[252] Exh. PG&E-03 at 3-42.

[253] Customers with usage that leads to distribution charges of $10 or more per month experience no bill impact from a $10 minimum bill. Relatively low usage of ~ 100kWh per month would be sufficient to exceed this amount.

7.2.1. Application of Article 12 of the Rules

The Commission has long favored the settlement of disputes. Article 12 of the Rules generally concerns settlements. Pursuant to Rule 12.1(d), 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 uncontested. The residential rate design settlement is uncontested.

This decision applies the requirements of Article 12 to each of the residential rate design issues resolved by the residential rate design settlement in turn below.

7.2.2. Schedule E-1 Tier Differentials

The parties initially litigated the question of how to adjust the tier differentials of PG&E's Schedule E-1 (the traditional residential tiered rate) in between GRC Phase 2 decisions. D.15-07-001 established the ratio to be used in setting the price of Tier 2 electricity for customers on PG&E Schedule E-1 at 125 percent of the price of Tier 1 electricity for a price ratio of 1.25. A third element of Schedule E-1's rate design – the High Usage Charge – is likely to be eliminated by PG&E in 2022 and is not specifically considered in this decision.[254]

PG&E proposed to effectively modify this ratio over time by fixing the cent-per-kWh difference between Tier 1 and Tier 2 for Schedule E-1 at the value of the cent-per-kWh differences reached at the end of 2022. While this would maintain the existing 1.25 price ratio at first, over time the ratio would be lowered as rates rise.[255] This would have the effect of flattening the prices on

[254] *See* D.21-03-003.

[255] For any given ratio, if the ratio is converted into a static cent-per-kWh differential, then any increase in rates will lower the ratio between the prices of the two tiers. Decreases in rates

Schedule E-1 in the long term. PG&E reasoned that its proposal was justified as maintaining a 1.25 price ratio would mean that the cents-per-kWh difference between Tier 1 and Tier 2 prices would expand unsustainably in the future as rates rose, particularly for customers in hot climate zones that rely on air conditioning during the summer.

Cal Advocates argued that the Commission should reject PG&E proposal as it does not provide the benefits for hot climate zone customers that it purports to. Cal Advocates also asserted that "PG&E's proposal would lead to relatively larger percentage bill increases over time for low usage customers than higher usage customers. This relative difference in impact is because any cents-per-kWh change equates to a larger percentage increase to lower tier rates than higher tier rates."[256] Cal Advocates also recommended that the Commission simultaneously consider this change for SCE and SDG&E customers if it was inclined to adopt PG&E's proposal.

The residential rate design settlement claimed that the parties to the settlement agreed that "the E-1 rate values for Tier 1, Tier 2 and the High Usage Charge (HUC) tier will be set according to the tiered rate ratios directed by the Commission in D.15-07-001, as modified by D.20-05-013 and D.21-03-003." The residential rate design settlement also stated that the settling parties agreed "PG&E's uncontested proposal for tiered rate levels for Schedule E-1 is reasonable and should be approved."[257]

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would have the opposite effect, but no party has offered evidence that PG&E's rates are expected to decrease.

[256] Exh. Cal Advocates-01 at 7-11.

[257] Residential rate design settlement at 9.

As noted above, PG&E's proposals were contested by Cal Advocates, but this decision assumes that Cal Advocates has settled this issue through the residential rate design settlement and now supports PG&E's proposal to fix the cent-per-kWh difference between Tier 1, Tier 2, and HUC for Schedule E-1 at the absolute value of the cent-per-kWh differences reached at the end of 2022. This decision also assumes that this fixing of cent-per-kWh differences is what the residential rate design settlement refers to when is refers to "E-1 rate values…set according to the tiered rate ratios…".[258]

The motion to adopt the residential rate design settlement argued that this outcome was reasonable in light of the whole record, consistent with law, and in the public interest. With respect to the condition that the outcome be reasonable in light of the whole record, the motion argued that the agreed rates fall within the range of parties' positions on the contested issues and that the settlement was reached only after substantial give-and-take through arms-length negotiations, after each party had made significant concessions to resolve issues in a manner that reflects a reasonable compromise of their litigation positions. With respect to the conditions that the outcome be consistent with the law and in the public interest, the motion argued that the fixing of Schedule E-1 tier differentials complied with all applicable statutes and prior Commission decisions, including Public Utilities Code Section 451, and that the negotiated settlement reflected the interests of parties affected by the settlement given the participation of parties representing the interests of residential ratepayers.[259]

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[258] Ratios normally refer to percentage differences, rather than an absolute difference in cent-per-kWh as apparently intended by the residential rate design settlement.

[259] Motion to adopt residential rate design settlement at 16-17.

Strictly speaking, the resolution of the Schedule E-1 issue does not comply with all previous Commission decisions as it seeks to effectively modify D.15-07-001 at its holding that prices for Tier 2 electricity should be 25 percent higher than prices for Tier 1 electricity. That decision's holding was based on a statutory obligation to ensure that Schedule E-1 utilized an inclining block structure to incent conservation and provide a discount for baseline amounts of electricity. This raises a question as to whether the residential rate design settlement's disposition of this issue is compliant with the law and in the public interest.

However, many of the parties active in R.12-06-013, in which D.15-07-001 was issued, are signatories to the residential rate design settlement and this decision presumes that they were aware of the implications of proposing this effective modification of D.15-07-001 and agree that the statutory obligations surrounding an inclining block rate structure for Schedule E-1 continue to be fulfilled.[260] Given this presumption, this decision finds that the resolution of this issue by the residential rate design settlement is reasonable in light of the whole record, consistent with law, and in the public interest. Should the ratio between E-1 Tier 1 and Tier 2 prices decline to such an extent that the inclining block structure required by law is imperiled, parties are encouraged to seek Commission review of Schedule E-1 and appropriate adjustments.

7.2.3. Schedule E-TOU-C Summer Tier Differentials

The residential rate design settlement proposed that the Schedule E-TOU-C peak versus off-peak price differentials should be kept at their current levels

[260] This proposed decision is being served to the service list of Rulemaking 12-06-013 to provide the opportunity for parties to comment on the modification to D.15-07-001 provided in the residential rate design settlement.

until twelve months after the last cohort of PG&E's customers is migrated to default TOU rates. For the period after that (*i.e.*, the period beginning twelve months after the last cohort has been migrated), the residential rate design settlement proposed a gradual increase in the cents per kWh peak to off-peak differentials (from 6.3 to 8.3 cents per kWh in summer, and from 1.7 to 2.8 cents per kWh in winter) that would then remain in place until the Commission issues a decision in PG&E's next GRC Phase 2 proceeding.

The residential rate design settlement laid out the following three-step process for increasing the peak to off-peak differential beginning in approximately May 2023:

- Step 1 Change Period (May 2023 – April 2024): Schedule E-TOU-C summer and winter POPP differentials shall be set as follows:
    - Summer: A total differential of $0.08344 per kWh (consisting of a $0.06344 generation rate differential and a $0.02000 distribution rate differential)
    - Winter: A total differential of $0.02835 (consisting of a $0.02503 generation rate differential and a $0.00332 distribution rate differential)
- Step 2 Change Period (May 2024 – April 2025): Schedule E-TOU-C summer and winter POPP differentials shall be set as follows:
    - Summer: A total differential of $0.10300 per kWh (consisting of a $0.08300 generation rate differential and a $0.02000 distribution rate differential)
    - Winter: A total differential of $0.03000 (consisting of a $0.02668 generation rate differential and a $0.00332 distribution rate differential)

- Step 3 Change Period (May 2025 – April 2026): Schedule E-TOU-C summer and winter POPP differentials shall be set as follows:
    - Summer: A total differential of $0.12300 per kWh (consisting of a $0.10300 generation rate differential and a $0.02000 distribution rate differential)
    - Winter: A total differential of $0.03000 (consisting of a $0.02668 generation rate differential and a $0.00332 distribution rate differential)[261]

Given the uncertainty as to whether the Commission will issue a decision in PG&E's next GRC Phase 2 proceeding before the completion of the E-TOU-C adjustment period in 2026, the parties to the residential rate design settlement agreed that, notwithstanding the change periods and POPP differentials proposed by the settlement, the Commission decision in PG&E's next GRC Phase 2 proceeding would take precedence with respect to implementing any changes to the POPP differentials in Schedule E-TOU-C.[262]

The motion to adopt the residential rate design settlement argued that this outcome was reasonable in light of the whole record, consistent with law, and in the public interest. With respect to the condition that the outcome be reasonable in light of the whole record, the motion argued that the agreed E-TOU-C differentials fall within the range of parties' positions on the contested issues, and that the settlement was reached only after substantial give-and-take through arms-length negotiations and after each party had made significant concessions to resolve issues in a manner that reflects a reasonable compromise of their litigation positions. With respect to the conditions that the outcome be

[261] Residential rate design settlement at 10-11.

[262] Residential rate design settlement at 11.

consistent with the law and in the public interest, the motion argued that the adjustments to the E-TOU-C differentials complied with all applicable statutes and prior Commission decisions, including Public Utilities Code Section 451, and that the negotiated settlement reflected the interests of parties affected by the settlement given the participation of parties representing the interests of residential ratepayers.[263]

This decision agrees with the motion on this matter and finds that the residential rate design settlement's treatment of Schedule E-TOU-C differentials is reasonable in light of the whole record, consistent with the law, and in the public interest.

7.2.4. New Schedule E-ELEC

In D.20-03-002 the Commission directed PG&E to propose in this proceeding a new opt-in, untiered residential TOU rate with a fixed charge. The intent of the order was to consider the creation of a rate that would incent beneficial residential electrification in PG&E's territory by lowering volumetric rates through the use of a fixed charge, and therefore lowering the cost of residential electrification at the margin.

PG&E complied with the directive of D.20-03-002 and proposed a new rate, Schedule E-ELEC, that would apply to the entirety of a residence's electric usage. Residential customers would be eligible for E-ELEC if the customer uses electricity for either of: 1) EV charging, 2) energy storage charging, or 3) electric heat pumps used for a) water heating and/or b) space conditioning (i.e., heating or cooling).[264] In order to maximize customer choice, PG&E proposed to modify

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[263] Motion to adopt residential rate design settlement at 16-17.

[264] Exh. PG&E-05 at 1-3.

Schedule EV2's applicability language to permit customers with heat pumps to qualify for that rate as well.[265] That would ensure that, if Schedule E-ELEC were adopted, customers with the three qualifying technologies mentioned above could choose from two different rates to reduce the marginal cost of their adopted technologies. PG&E proposed to make E-ELEC available to CARE and FERA customers with qualifying technologies, who would then see a line item discount of 35 percent and 18 percent, respectively, on their bills. PG&E proposed to not allow participation from medical baseline customers, consistent with their exclusion from Schedule EV2. PG&E's rationale was that the medical baseline program is only compatible with tiered rate structures (where additional baseline amounts can be provided). A tiered rate, and baseline quantities, are missing from E-ELEC and EV2.[266]

The new rate would utilize PG&E's current base TOU periods, a $25 per month fixed charge, and moderated generation and distribution price differentials. According to PG&E, adopting a $25 fixed charge would reduce volumetric rates by $0.055/kWh to incentivize electrification at the margin. PG&E proposed to apply the volumetric rate reduction equally to each TOU period. Finally, PG&E proposed to update Schedule E-ELEC rates between GRC Phase 2 proceedings using an equal-cents-per-kWh method to maintain the cents-per-kWh differentials between TOU periods on a constant basis. PG&E did not propose to change the fixed monthly charge between GRC Phase 2 proceedings.

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[265] Exh. PG&E-05 at 1-4 and 1-5.

[266] Exh. PG&E-05 at 1-11.

Cal Advocates recommended a fixed charge of $12.21 per month (based on an average of the MCAC values presented by Cal Advocates and PG&E). Cal Advocates asserted an averaging of MCAC values was appropriate as PG&E had not presented a cost basis for a proposed $25 fixed charge and instead based the value on policy considerations.

The residential rate design settlement proposed to resolve the design of E-ELEC by adopting TOU rate differentials as proposed by PG&E and setting a fixed charge at $15 per customer per month. The fixed charge is proposed to be a distribution rate component that shall be used to reduce the distribution rate component in each and every E-ELEC TOU period by an identical cents-per kWh amount from what their levels would have been absent a fixed charge.[267]

Specifically, the TOU rate differentials for Schedule E-ELEC are proposed to be $0.21856 per kWh between peak and off-peak in the summer (consisting of a $0.14421 generation rate differential and a $0.07434 distribution rate differential), $0.05668 per kWh between part-peak and off-peak in the summer (consisting of a $0.04510 generation rate differential and a $0.01158 distribution rate differential), $0.03595 per kWh between peak and off-peak in the winter (consisting of a $0.03332 generation rate differential and a $0.00263 distribution rate differential), and $0.01386 per kWh between part-peak and off-peak in the winter (consisting of a $0.01335 generation rate differential and a $0.00052 distribution rate differential).[268]

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[267] Residential rate design settlement at 12.

[268] Residential rate design settlement at 12.

The illustrative rate design for Schedule E-ELEC, as proposed by the residential rate design settlement and estimated in Attachment 2 to Exhibit PG&E-49, appears below:

E-ELEC Rate Component	Price
Monthly Fixed Charge	$15
Summer[269] Peak (4 pm – 9 pm)	$0.43340/kWh
Summer Part-Peak (3 – 4pm, 9 pm – 12 am)	$0.27152/kWh
Summer Off-Peak (12 am – 3 pm)	$0.21484/kWh
Winter[270] Peak (4 pm – 9 pm)	$0.24032/kWh
Winter Part-Peak (3 – 4pm, 9 pm – 12 am)	$0.21823/kWh
Winter Off-Peak (12 am – 3 pm)	$0.20437/kWh

With respect to implementation, the residential rate design settlement suggests that Schedule E-ELEC would be ready for customer adoption on an opt-in basis by a date 12 months after the effective date of this decision.

The parties to the residential rate design settlement believed that key information regarding customers who engage in electrification efforts "should be collected and provided to interested stakeholders and the Commission, which could then be used to inform both programmatic enhancements and rate design. The information would be provided as part of a formal Measurement and Evaluation (M&E) study[271] that has predefined size, scope, and deliverables, and would be determined via a workshop setting to take place no more than 90 days after PG&E's 2020 GRC Phase [2] Decision is issued."[272] The residential rate

[269] PG&E's summer season is June – September.

[270] PG&E's winter season is October – May.

[271] The residential rate design settlement proposed that the M&E study reporting be completed approximately one year and 60 days after the implementation of Schedule E-ELEC, to provide the results of the M&E study and supporting analyses to interested parties.

[272] Residential rate design settlement at 13.

design settlement therefore proposed that PG&E host two workshops with the following timeline and objectives:

- Workshop #1: Within 90 days of the effective date of this decision, a workshop will be held to define the size, scope, and deliverables of the M&E study (*e.g.*, study objectives, number of customers to be included in the sample, potential control group). The workshop should also discuss and consider an *ex ante* sensitivity analysis plan.
- Workshop #2: Approximately one year and 90 days after the implementation of Schedule E-ELEC, a workshop will be held to discuss the results of a proposed M&E study and assess what changes (if any) could be implemented to E-ELEC along with the appropriate mechanism (*e.g.*, increase the fixed charge and lower the volumetric charges via a Rate Design Window or another GRC proceeding).

With respect to ME&O, the residential rate design settlement proposed that the E-ELEC rate be promoted to PG&E's residential customers mainly through existing channels, rather than through the development of new forms of outreach.

The motion to adopt the residential rate design settlement argued that the adoption of Schedule E-ELEC, as defined by the settlement, was reasonable in light of the whole record, consistent with law, and in the public interest. With respect to the condition that the outcome be reasonable in light of the whole record, the motion argued that the ultimately agreed-to design of E-ELEC falls within the range of parties' positions, and that it was reached only after substantial give-and-take through arms-length negotiations after each party had made significant concessions to resolve issues in a manner that reflects a reasonable compromise of their litigation positions. With respect to the conditions that the outcome be consistent with the law and in the public interest, the motion argued that the adoption of Schedule E-ELEC complied with all applicable statutes and prior Commission decisions, including Public Utilities Code Section 451, and that the negotiated settlement reflected the interests of parties affected by the settlement given the participation of parties representing the interests of residential ratepayers.[273]

This decision agrees with the motion that the ultimate design of Schedule E-ELEC lies within the litigated positions of the parties and is therefore reasonable in light of the whole record.

In order to find that the settlement's disposition on the issue of a fixed charge for E-ELEC customers complies with the law, it is necessary to address testimony proffered by Cal Advocates that raised important general questions concerning the appropriate manner for designing residential fixed charges. Specifically, in its testimony Cal Advocates declined to apply EPMC scaling when deriving its proposed E-ELEC fixed charge from proposed MCAC values. Cal Advocates claimed this exclusion of EPMC was "based on previous Commission precedent"[274] despite the fact that the Commission wholeheartedly supports the EPMC method. They cited the Commission's decision identifying fixed cost categories to be included in a *default* residential fixed charge (D.17-09-035) as excluding the use of the EPMC scalar for purposes of setting a *default* residential fixed charge, finding that "there is no separate EPMC scaling process that includes customer related costs only" and that doing so would

[273] Motion to adopt residential rate design settlement at 16-17.

[274] Exh. Cal Advocates-01 at 7-14.

recover a mix of demand-related and customer-related costs in a customer-related charge.[275]

The issue considered by D.17-09-035 is easily distinguishable. There the issue was the appropriate costs to be used as a basis for a residential fixed charge that would apply to all customers regardless of their particular rate schedule. Here, the Commission is considering only one *optional* residential rate. Additionally, the design of the fixed charge for E-ELEC is intended to further state policy goals related to decarbonization and therefore has a particular policy purpose that may justify any dissonance with previous Commission decisions regarding the application of EPMC to residential fixed charges.

For all of these reasons, this decision finds that D.17-09-035 does not hold precedential value outside of the context of its originating proceeding (A.16-06-013). That proceeding and the omnibus residential rate reform rulemaking (R.12-06-013) closed years ago without adopting a residential fixed charge based on the cost categories identified by D.17-09-035. This decision therefore finds that any future proposals for a default residential fixed charge or optional residential fixed charge (as in this case) should be able to proceed without the need to comply with cost category and EPMC determinations made in a since-closed proceeding that failed to make a determination concerning a residential fixed charge on the merits.[276]

[275] Exh. Cal Advocates-01 at 7-14, citing D.17-09-035 at 27-28.

[276] Obviously, the mandates of Public Utilities Code Section 739.9 would continue to apply to any consideration of default residential fixed charges, but the Commission's analysis of that section may proceed *de novo* without reliance on the findings of D.17-09-035.

For all of these reasons, the residential rate design settlement's proposal for a $15 monthly fixed charge for E-ELEC customers is consistent with the law and previous Commission decisions.

The final issue is whether the proposed design of Schedule E-ELEC is in the public interest. On balance, this decision finds that it is in the public interest as it complies with the Commission's directive to create an untiered TOU rate with a monthly fixed charge that will reduce the marginal cost of electrification for residential customers and therefore support the state's policy goals surrounding electrification of residences and transportation.

7.2.5. Medical Baseline Participation

While this decision finds that the proposed Schedule E-ELEC is consistent with the public interest on balance, PG&E's exclusion of medical baseline customers from E-ELEC and EV2, while apparently justified by the current understanding of the requirements of the medical baseline program, is contrary to state policy goals to incent residential electrification and electric vehicle adoption. One could easily imagine why medical baseline customers would be particularly interested in energy storage or electric vehicles capable of supplying vehicle-to-load in order to hedge against outages that threaten their ability to use vital medical equipment. This decision orders PG&E to propose an expansion of Schedule E-ELEC and Schedule EV2 eligibility to include medical baseline customers. The statute and Commission orders governing the medical baseline program should be examined to determine how to allow medical baseline customers to take advantage of these untiered rates (*e.g.*, by providing a certain line item discount to account for savings that may have otherwise been realized on a tiered rate). PG&E is encouraged to work with stakeholders representing the interests of medical baseline customers and the Commission's Energy

Division in preparing the proposal. PG&E shall propose such an expansion in a Tier 3 advice letter filed with the Commission no later than 12 months after the effective date of this decision. The advice letter will be disposed of via a Commission resolution prepared by the Commission's Energy Division.

7.2.6. Measurement and Evaluation of E-ELEC

The residential rate design settlement proposed that an M&E plan should be developed and executed for Schedule E-ELEC. This decision approves the residential rate design settlement, and therefore does not reject the concept of an M&E plan outright. However, there is little record to support the development and execution of an M&E plan for Schedule E-ELEC other than the apparent interest of the parties in conducting such a study. This decision does not approve a particular budget or scope for the M&E plan. Once the M&E plan is developed by the parties through their workshop process, PG&E should propose an M&E plan and budget for the Commission to consider via a Tier 3 advice letter. The Commission may approve, reject, or modify the proposed M&E plan and budget depending on the record developed during the consideration of PG&E's Tier 3 advice letter. The Commission will dispose of the M&E plan advice letter through a Commission resolution prepared by the Commission's Energy Division.

7.2.7. Electric and Gas Baseline Quantities

PG&E proposed to revise its method for calculating the baseline electricity allotments for its residential customers. Instead of using a method that relies on simple recorded historic usage, PG&E wished to revert to an older method of using weather-normalized historic usage to determine baseline quantities. PG&E believed that this reversion was reasonable because 1) using it would reduce unintended and undesirable fluctuations in baseline allowance levels and resulting bill volatility adopted from one rate case baseline update to the next, and 2) using it would better incorporate changes in customer usage in this era of increasing energy transformation as reflected in the adopted residential gas and electric sales forecasts. PG&E also argued that its proposal supported SB 711 goals to consider bill volatility in gas and electric rate design applications and was authorized by the Commission in D.04-04-026 for purposes of updating baseline allowances.[277]

TURN's testimony cited concerns that using this older method could lead to adverse bill impacts.

The residential rate design settlement stated that "[t]he parties agree with PG&E's proposal to revert to the previously adopted method of using weather-normalized historic usage instead of recorded historic usage to determine electric and gas baseline allowances."[278] To address TURN's concerns regarding potential bill impacts, the residential rate design settlement developed the proposed baseline quantities based on the target percentages of usage adopted by the Commission in D.18-08-013, with caps applied to the changes in baseline quantities to stabilize bill impacts. The caps limit changes in baseline quantities compared to quantities approved in D.18-08-013 to no more than five percent for Basic and All-Electric service customers in summer, no more than eight percent for Basic service customers in winter, and no more than five percent for All-Electric customers in winter. A cap is not proposed for the winter baseline quantity for All-Electric service customers in Territory V, which the

[277] Exh. PG&E-03 at 3-8.

[278] Residential rate design settlement at 15.

settlement proposed be set at 19.1 kWh per day, as originally proposed by PG&E.[279]

The electric baseline quantities proposed for PG&E's residential customers by the residential rate design settlement appear below. These quantities would be applied to residential customers, with revenue-neutral rate adjustments, on their respective first seasonal change after a final Commission decision is rendered in this proceeding (likely to be October 2021 for E-1 and E-TOU-C customers).

Individually-Metered customers, figures in kWh per day:

	Basic Electric		**All-Electric**	
Baseline Territory	**Summer**	**Winter**	**Summer**	**Winter**
P	13.5	11.0	15.2	26.0
Q	9.8	11.0	8.5	26.0
R	17.7	10.4	19.9	26.7
S	15.0	10.2	17.8	23.7
T	6.5	7.5	7.1	12.9
V	7.1	8.1	10.4	19.1
W	19.2	9.8	22.4	19.0
X	9.8	9.7	8.5	14.6
Y	10.5	11.1	12.0	24.0
Z	5.9	7.8	6.7	15.7

Master-Metered customers, figures in kWh per day:

	Basic Electric		**All-Electric**	
Baseline Territory	**Summer**	**Winter**	**Summer**	**Winter**
P	4.6	4.8	8.4	15.3
Q	5.1	4.8	6.9	15.3
R	7.5	4.9	9.1	12.9
S	6.4	5.0	9.3	12.4
T	3.6	4.1	4.8	8.6

[279] Residential rate design settlement at 15, fn 19.

V	4.0	4.6	6.0	10.6
W	7.8	5.0	11.1	11.2
X	5.1	5.4	6.9	12.3
Y	7.6	7.6	6.7	13.7
Z	4.3	5.2	4.2	9.0

With respect to gas baseline quantities, the residential rate design settlement proposed to adopt PG&E's proposals for gas baseline allowances and sought approval of PG&E's proposal to update future gas residential baseline quantities in PG&E's Gas Cost Allocation Proceeding (GCAP), instead of in the GRC Phase 2 proceeding.

The residential rate design settlement recommended that the Commission not adjust PG&E's baseline territory boundaries. The settlement also proposed to adopt PG&E's proposed Post-Calculation Adjustments described in PG&E's Electric Baseline Allowance Workpapers and PG&E's proposal to update GM-W Baseline Allowances provided to building owners (which have been unchanged since 1984) using a three-year phase-in to mitigate impacts.[280]

TURN proposed that a workshop be held on baseline quantities to determine the appropriate treatment of NEM customers in baseline calculations. The residential rate design settlement adopted this proposal, and states that no later than 12 months after the effective date of this proceeding, PG&E will conduct a workshop on the topic of the treatment of NEM customer load in baseline quantity calculations.[281]

The motion to adopt the residential rate design settlement argued that the adoption of the proposed electric and gas baseline quantities, as defined by the settlement, was reasonable in light of the whole record, consistent with law, and

[280] Residential rate design settlement at 16.

[281] Residential rate design settlement at 17.

in the public interest. With respect to the condition that the outcome be reasonable in light of the whole record, the motion argued that the proposed baseline quantities fall within the range of parties' positions, and that it was reached only after substantial give-and-take through arms-length negotiations after each party had made significant concessions to resolve issues in a manner that reflects a reasonable compromise of their litigation positions. With respect to the conditions that the outcome be consistent with the law and in the public interest, the motion argued that the adoption of the proposed baseline quantities complied with all applicable statutes and prior Commission decisions, including Public Utilities Code Section 451, and that the negotiated settlement reflected the interests of parties affected by the settlement given the participation of parties representing the interests of residential ratepayers.[282]

The proposed electric baseline quantities do not represent as large a decrease from current quantities as originally proposed by PG&E. They therefore fall within the range of options presented in this proceeding (*i.e.*, no change vs. PG&E's proposed decreases) and are reasonable in light of the whole record.

Whether or not the proposed electric baseline quantities are consistent with the law and Commission decisions depends on the reasonableness of PG&E's methodology. The residential rate design settlement claims that the methodology used by PG&E in this proceeding complies with a methodology that was approved by the Commission in D.04-04-026. No party disputed this assertion and therefore this decision finds that PG&E's proposal to use weather-

[282] Motion to adopt residential rate design settlement at 16-17.

normalized historic usage to calculate electric baseline quantities is reasonable and complies with the law and previous Commission decisions.

With respect to the public interest, the residential rate design settlement's proposed electric baseline quantities represent significant decreases from previously approved baseline quantities and therefore will result in adverse bill impacts for those customers that currently use their full allotment of baseline electricity. The residential rate design settlement's use of caps to limit the impact of PG&E's originally proposed adjustments to residential electric baseline quantities mitigates this concern, as does the settlement's compliance with the law and Commission decisions in calculating the proposed baseline quantities. For these reasons, this decision finds that the proposed electric baseline quantities are in the public interest despite the potential adverse bill impacts for a certain number of customers.

All other baseline issues disposed of by the residential rate design settlement were uncontested by any party, and therefore this decision finds that the settlement's positions on those issues are reasonable in light of the whole record, compliant with the law, and in the public interest.

7.2.8. Master Meter Discounts

The residential rate design settlement proposed that once the rate designs and revenue allocation adopted by this decision go into effect, the Schedule ET base portion of the net master meter discount (Base) would be fixed at its 2020 level of $5.07 per space per month. The Schedule ES Base would be set at $3.57 per space per month as originally proposed by PG&E.

Furthermore, the residential rate design settlement proposed that PG&E implement the baseline Diversity Benefit Adjustment (DBA) and Line Loss Adjustment (LLA) portion of the net master meter discount a) at the then-current rates upon 2020 GRC Phase 2 implementation, and b) using a re-run of the DBA and LLA upon implementation of changes to the residential HUC pursuant to D.21-03-003. The Schedule ES DBA would be set at 58 percent of the Schedule ET DBA in each of part a) and part b) above. The Schedule ES LLA would be set to $0 per space per month. The total master meter discount would be calculated as follows: 1) Schedule ET Net Master Meter Discount = Base + LLA – DBA, and 2) Schedule ES Net Master Meter Discount = Base – DBA.[283]

The motion to adopt the residential rate design settlement argued that the adoption of the proposed master meter rates, as defined by the settlement, was reasonable in light of the whole record, consistent with law, and in the public interest. With respect to the condition that the outcome be reasonable in light of the whole record, the motion argued that the proposed master meter rates fall within the range of parties' positions, and that it was reached only after substantial give-and-take through arms-length negotiations after each party had made significant concessions to resolve issues in a manner that reflects a reasonable compromise of their litigation positions. With respect to the conditions that the outcome be consistent with the law and in the public interest, the motion argued that the adoption of the proposed master meter rates complied with all applicable statutes and prior Commission decisions, including Public Utilities Code Section 451, and that the negotiated settlement reflected the

[283] Residential rate design settlement at 18. The settlement also proposed certain understandings related to potential residential fixed charges and their applicability to master metered customers. This decision does not specifically consider that part of the settlement given that the question of residential fixed charges is not before the Commission at this time. The parties to the settlement are encouraged to present this portion of the settlement to the Commission if residential fixed charges are considered in the near future.

interests of parties affected by the settlement given the participation of parties representing the interests of residential ratepayers.[284]

The proposed master meter rates fall within the range of outcomes sought by the parties, as evidenced by Appendix 1 to the residential rate design settlement. The proposed master meter rates are therefore reasonable in light of the whole record. No party disputed that the proposal is consistent with the law and in the public interest, and there is no record to suggest otherwise. In light of these findings, this decision finds that the proposed master meter rates comply with the law and are in the public interest.

7.2.9. Approval of Residential Rate Design Settlement

In light of the findings laid out previously, this decision finds that the residential rate design settlement is reasonable in light of the whole record, complies with the law, and is in the public interest. Therefore, this decision approves the residential rate design settlement and PG&E shall implement its provisions as soon as practicable.

8. Streetlight Settlement Agreement

PG&E served and filed a motion to adopt a settlement on streetlight rate design issues (SSA) on February 23, 2021. The motion was filed on behalf of PG&E and CALSLA.[285] One other party (the City and County of San Francisco) participated in settlement negotiations on streetlight rate design issues, but that party did not sign the settlement due to time constraints. However, the motion to adopt the SSA indicates that the City and County of San Francisco supports

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[284] Motion to adopt residential rate design settlement at 16-17.

[285] With respect to the portion of the SSA related to a dimmable streetlights program, CALSLA joined the settlement on behalf of the City of San Jose. (SSA at 8.)

portions of the settlement not related to a dimmable streetlights program,[286] and does not object to the portions of the SSA related to a dimmable streetlights program.[287] The motion to adopt the SSA asked that the Commission accept the SSA as uncontested, and this decision does so.

The SSA adopts several proposals for streetlight rate design, including the following:

- PG&E's proposed, uncontested rate design for Schedule LS-3, including the proposed customer charge.
- PG&E's proposed facility charges for Schedules LS-1, LS-2, OL-1 and CCSF, at full cost levels as shown in Exhibit PG&E-03, Table 6-2.
- Adjustment of facility rates by moving them 1/12th of the way to full cost each year of any full cost "phase in" period, or 1/12th of the way to full cost in a single year if there is no "phase in" period.[288]
- PG&E's proposals for the light-emitting diode (LED) Conversion Program.
- Elimination of the Incremental Facility Charge (IFC) for non-decorative lamps subject to LED conversion.
- Reduction of the IFC to $6.226 per lamp for decorative lamps subject to LED conversion.
- Resolution of contested dimmable streetlight program issues, including the creation of a pathway for future development of a rate design and program to support dimmable streetlights if certain conditions are met.
- Elimination of the Dimmable Streetlight Pilot Program adopted by D.15-08-005.

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[286] Motion to adopt SSA at 12, fn 13.

[287] SSA at 8, fn 8.

[288] SSA at 7-8.

- Continuation of the Dimmable Streetlight Pilot Program authorized in D.11-12-053, in which the City of San Jose is participating, and establishment of communication standards for PG&E and the City of San Jose.

8.1. Application of Article 12 of the Rules

The Commission has long favored the settlement of disputes. Article 12 of the Rules generally concerns settlements. Pursuant to Rule 12.1(d), 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 uncontested. The SSA is uncontested.

The motion to adopt the SSA claimed that the settlement should be found to be reasonable in light of the whole record as it adopts compromises between the parties on disputed issues that are within the range of litigated positions.[289] Appendix 1 to the SSA reveals that the settlement's terms are indeed within the range of litigated positions, and therefore this decision finds that the SSA is reasonable in light of the whole record.

The motion to adopt the SSA claimed that the settlement should be found to be consistent with the law "as it complies with all applicable statutes and prior Commission decisions" including Public Utilities Code Section 451.[290] No party disputed that the SSA complied with all applicable statutes and prior Commission decision, and therefore this decision finds that the SSA is consistent with the law.

The motion to adopt the SSA claimed that the settlement should be found to be in the public interest because it represents a reasonable compromise of

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[289] Motion to adopt the SSA at 13.

[290] Motion to adopt the SSA at 13.

litigated positions, avoids further litigation on streetlight rate designs in this proceeding, provides rate certainty for streetlight customers going forward, and accounts for the real-world experience of the City of San Jose in attempting to implement a dimmable streetlight pilot program.[291] This decision agrees with these assertions and therefore finds that the SSA is in the public interest.

Because the SSA complies with the requirements of Rule 12.1 as described above, this decision holds that it is reasonable to adopt the SSA in its entirety.

8.2. Future Implementation of Dimmable Streetlight Rate Design

The SSA's settlement of contested issues related to dimmable streetlights and ancillary devices attached to streetlights that utilize customer-owned meters incorporates specific guiding principles for parties to use in the future to develop new rate designs for metered dimmable streetlights or ancillary devices. As a part of the settlement of those issues, PG&E is granted discretion to determine compliance with a party's ability to meet metering and data delivery requirements as set forth in Electric Rule 22.[292] CALSLA and its members are encouraged to contact the Commission's Energy Division if any disputes arise between CALSLA members and PG&E in the course of PG&E's exercise of this discretion. The potential development of a dimmable streetlight rate design and program should be expeditiously pursued under the SSA's terms, and this decision holds that disputes between parties should not unnecessarily interfere with such development. Disputes should be resolved as quickly as possible, using the Commission's assistance if necessary.

[291] Motion to adopt the SSA at 14-15.

[292] SSA at 10.

9. Economic Development Rate

The Economic Development Rate (EDR) provides a discounted rate to certain commercial and industrial customers in order to attract businesses to California or provide an incentive for existing California businesses to avoid leaving California. The premise of EDR is that by providing a discounted electricity rate to certain businesses, the employment and other economic benefits related to the business's operations may be retained by California.[293]

PG&E cited Public Utilities Code Section 740.4(a) as supporting the existence of EDR. That part of the statute requires the Commission to authorize utilities to "engage in programs to encourage economic development." It should be noted that this Section does not require the Commission to authorize a rate discount, although the Commission historically approved rate discounts to effectuate the Section.[294]

PG&E's current EDR program offers three rate reduction tiers that depend on the annual average of the city or county unemployment rate at the business's location. The current rate reduction tiers provide 12 percent, 18 percent, or 25 percent off the business's monthly electricity bill, with the greater discounts going to projects in cities and counties with higher unemployment rates. PG&E's EDR Tier 2 provides an 18 percent rate reduction for those cities and counties that have an annual unemployment rate between 130 and 150 percent of California's statewide average. Tier 3, the 25 percent rate reduction, is only available in those cities and counties that have an annual unemployment rate

[293] Exh. PG&E-03 at 7-1 ("PG&E proposes to continue offering its EDR to attract jobs and companies to locate in California when they have out-of-state choices and to retain companies considering leaving California").

[294] *See, e.g.,* D.13-10-019 authorizing PG&E to offer a maximum rate reduction of 30 percent to help California compete for out-of-state business.

above 150 percent of California's statewide average. For all other areas of PG&E's service territory, qualifying businesses are eligible for the standard 12 percent rate reduction under Tier 1.[295]

In order to qualify for an EDR rate discount, a business must fulfill several qualifying criteria. These are:

- Have out-of-state options for a new facility or an expansion facility or have a current operation in California that is at risk of ceasing operations.
- Supply documentation to show out-of-state choices or other operational scenarios.
- Sign an affidavit attesting to the fact that but for the EDR rate discount, either on its own or in combination with a package of offerings, the business would not have retained or expanded its load within California or would not have located in California.
- Pass an eligibility review with the California Governor's Office of Business and Economic Development.
- Be a relocatable type of business, e.g., a retail store is not a relocatable business because it is locally tied to its consumer base.
- Submit an annual report that includes the number of jobs, types of jobs, and average wages and benefits for the jobs created or retained.[296]

There is a cap on enrollment in the EDR program. Currently, PG&E may enroll a further 140 MW of total load in the EDR program, with certain carve-outs of the 140 MW for each Tier of EDR discount.[297]

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[295] Exh. PG&E-03 at 7-2 and 7-3.

[296] Exh. PG&E-03 at 7-2.

[297] Exh. PG&E-03 at 7-4.

PG&E proposed to retain three rate reduction tiers and the current associated unemployment thresholds. The standard (Tier 1) and mid-enhanced (Tier 2) would remain in place with rate reductions of 12 percent and 18 percent, respectively, and the enhanced tier (Tier 3) rate reduction would be lowered from 25 percent to 20 percent. PG&E also proposed that the EDR cap be increased by 150 MW, and that the cap increase apply to all three rate reduction tiers for businesses with 150 kW of demand or more, and a 5 MW cap increase for small businesses with under 150 kW of demand. PG&E further recommended that any unused load space from the existing EDR program be rolled over into the EDR program approved in this proceeding and applied using the same tiered bucket rules from the existing EDR program.[298]

Two other parties commented on PG&E's EDR proposals. Cal Advocates believed that the EDR program should be simplified and therefore recommended the merging of EDR tiers to create two tiers instead of three (*i.e.*, by removing the middle tier) with reductions of 12 percent and 20 percent. Cal Advocates also requested that the Commission direct PG&E to conduct a survey of businesses to identify issues with enrollment or participation in EDR and report the results in PG&E's next GRC Phase 2 application.[299] Among other recommendations, the Joint CCAs proposed a much stronger weighting of the EDR discount toward the generation component of a customer's rate, rather than the distribution component.[300]

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[298] Exh. PG&E-03 at 7-16.

[299] Exh. Cal Advocates-01 at 8-3 through 8-8.

[300] Exh. Joint CCAs-01 at 18, 24.

9.1. EDR Settlement

On April 8, 2021, PG&E served and filed a motion seeking adoption of an Economic Development Rate Supplemental Settlement Agreement (EDR settlement). The motion claimed to resolve all EDR issues in the current proceeding. The motion stated that the parties to the EDR settlement are EUF, Joint CCAs, PG&E, Cal Advocates, and SBUA. Because the parties serving testimony on EDR issues signed the EDR settlement, the EDR settlement is uncontested.

The motion to adopt the EDR settlement presented six main policy objectives for PG&E's EDR program. These are:

1. Attract jobs and companies to California when they have out-of-state choices, and retain jobs and companies that would otherwise cease operation or depart from California.
2. Maintain a 12 percent standard EDR discount, keeping the standard EDR discount consistent across the large electrical corporations in California.
3. Continue supporting smaller customers (those served at primary and secondary voltage) in the areas with the highest unemployment levels by offering higher EDR discounts of 18 percent or 20 percent to such customers in those areas.
4. Enable collaboration with CCAs to ensure that qualified customers receive attractive rates reductions throughout the PG&E service territory.
5. Establish rate reductions for EDR which aim to produce sufficient cost recovery to enable more retail electric sellers to offer rates similar to PG&E's EDR rates.

6. Ensure EDR customers pay all non-bypassable charges from the otherwise applicable tariff, including the PCIA.[301]

The EDR settlement noted that due to penetration of CCAs in PG&E's service territory, the EDR rate discounts may not be as effective as presumed if CCAs do not offer an EDR-like product for the generation portion of an EDR customer's rate. This is because the EDR discount applies to both generation and distribution rates, and as CCAs set the generation rates for their PG&E customers, if a CCA does not match the generation rate discount offered by PG&E's EDR program then a CCA customer would not be able to realize the full EDR discount.

In order to address this issue, the motion to adopt the EDR settlement claimed that PG&E and the Joint CCAs agreed to create a collaborative process "to identify and vet EDR applicants that will make it easier for CCAs to provide a generation rate reduction to CCA customers who qualify for PG&E's EDR."[302]

The EDR settlement recommended that the Commission adopt some of PG&E's uncontested EDR proposals: 1) roll over unused load space from the existing EDR program to the iteration of the program approved by this decision, 2) increase the EDR program cap by an additional 150 MW for businesses with peak loads of 150 kW or more, and increase the program cap by additional five MW for small businesses, and 3) update the allocation factors for EDR rate reductions to generation and distribution charges.[303]

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[301] Motion to adopt EDR settlement at 5.

[302] Motion to adopt EDR settlement at 6.

[303] Motion to adopt EDR settlement at 8.

With respect to the roll over of unused load space for customers with maximum demand of 150 kW or greater, the EDR settlement recommended that the unused load space should be allocated into four tier caps:

- Tier 1 - Standard EDR Load Cap, 20 percent
- Tier 2 – Mid-Enhanced EDR Load Cap, 20 percent
- Tier 3 - Enhanced EDR Load Cap, 20 percent
- Tier 4 - Unrestricted (Tiers 1, 2, or 3), 40 percent

With respect to the additional 150 MW of EDR program cap proposed by the EDR settlement for customers with maximum demand of 150 kW or greater, the EDR settling parties recommended that it be unrestricted and open to any EDR customer in any Tier.[304]

The EDR settlement recommended that the unused EDR program capacity for customers with peak demands under 150 kW should roll over and be unrestricted. The additional 5 MW in EDR Program Cap for customers with peak demands of less than 150 kW would be unrestricted.[305]

The updated allocation factors, or relative allocation of EDR discounts to generation and distribution charges, are proposed by the EDR settlement as follows:

	Transmission Voltage Customers	Primary Voltage Customers	Secondary Voltage Customers
Generation	78 percent	35 percent	40 percent
Distribution	22 percent	65 percent	60 percent

The EDR settlement recommended changes to the rate discounts offered by the EDR program. The new EDR rate discounts proposed are 12 percent for all EDR customers taking service at transmission level voltage, regardless of the

304 EDR settlement at 8.

305 EDR settlement at 8.

unemployment rate of the county or city where the customer is located, and for customers served at secondary or primary levels of voltage, a 12 percent rate discount for the "Standard Tier," an 18 percent discount for the "Mid-Enhanced Tier," and a 20 percent discount for the "Enhanced Tier."[306]

The eligibility of a business for the various tiers would be determined as follows:

- For the "Standard Tier" a customer need only meet the EDR eligibility requirements currently applicable to EDR program participants.
- For the "Mid-Enhanced Tier" a customer must meet the currently applicable EDR eligibility requirements, and be located in a county or city experiencing an annual unemployment rate between 130 percent and 150 percent of the state's average unemployment rate, but the actual unemployment rate is still above five percent, and either the county or city has an unemployment rate above five percent as of the date of the customer's EDR application.
- For the "Enhanced Tier" a customer must meet the currently applicable EDR eligibility requirements, and be located in a county or city experiencing an annual unemployment rate above 150 percent of the state's average unemployment rate, but the actual unemployment rate is still above five percent, and either the county or city has an unemployment rate above five percent as of the date of the customer's EDR application.[307]

[306] Motion to adopt EDR settlement at 8. This decision assumes that customers taking service at transmission level voltage would be considered eligible for any of new 150 MW of approved EDR program cap, and the application of the EDR settlement shall reflect this assumption.

[307] EDR settlement at 7. The third criterion for the Mid-Enhanced Tier and Enhanced Tier appears to be superfluous, but this decision does not disturb the criteria as proposed by the EDR settlement.

With respect to reporting, the EDR settlement proposed that PG&E continue the current evaluation and reporting concerning contracts executed under the EDR program.[308]

9.2. Application of Article 12 of the Rules

The Commission has long favored the settlement of disputes. Article 12 of the Rules generally concerns settlements. Pursuant to Rule 12.1(d), 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 uncontested. The EDR settlement is uncontested.

The motion to adopt the EDR settlement claimed that it should be found to be reasonable in light of the whole record as it adopts compromises between the parties on disputed issues that are within the range of litigated positions.[309] Appendix 1 to the EDR settlement reveals that the settlement's terms are indeed within the range of litigated positions, and therefore this decision finds that the EDR settlement is reasonable in light of the whole record.

The motion to adopt the EDR settlement claimed that the settlement should be found to be consistent with the law "as it complies with all applicable statutes and prior Commission decisions" including Public Utilities Code Section 451.[310] No party disputed that the EDR settlement complied with all applicable statutes and prior Commission decision, and therefore this decision finds that the EDR settlement is consistent with the law.

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[308] EDR settlement at 8.

[309] Motion to adopt EDR settlement at 11.

[310] Motion to adopt EDR settlement at 12.

The motion to adopt the EDR settlement claimed that the settlement should be found to be in the public interest because it represents a reasonable compromise of litigated positions, avoids further litigation on EDR issues in this proceeding, and "advances key stated goals of the Governor."[311] This decision agrees with these assertions. Furthermore, the six policy goals for the EDR program elucidated by the motion to adopt the EDR settlement are sound and reflect the public interest in the EDR program. For these reasons, this decision finds that the EDR settlement is in the public interest.

Because the EDR settlement complies with the requirements of Rule 12.1 as described above, this decision holds that it is reasonable to adopt the EDR settlement in its entirety. PG&E shall implement the terms of the EDR settlement as soon as practicable.

10. Agricultural Rate Design

PG&E served its prepared testimony on agricultural rate design issues on November 22, 2019, updated that testimony on May 15, 2020 and served errata testimony on July 16, 2020. Responsive testimony on agricultural rate design issues was served on November 20, 2020 by AECA and CFBF. PG&E served rebuttal testimony on February 26, 2021. Rebuttal testimony was served also on February 26, 2021 by AECA and CFBF. The main agricultural rate design proposals contained in party testimony are summarized below.

Several agricultural rate design modifications proposed by PG&E in its testimony were not contested by AECA or CFBF. These include:

- PG&E's proposals for new default agricultural Schedules AG-A1, AG-A2, AG-B and AG-C.

[311] Motion to adopt EDR settlement at 12.

- PG&E's proposed rate design for optional flexible TOU hours for Schedules AG-FA, AG-FB and AG-FC.
- PG&E's proposal to eliminate monthly TOU meter charges on legacy rate schedules.
- PG&E's proposal to implement solar legacy rate designs specified in D.18-08-013.
- PG&E's proposal for a Schedule AG-C Demand Charge Rate Limiter (DCRL).

AECA proposed several agricultural rate design modifications that were opposed by PG&E and therefore contested. These include:

- AECA's springtime agricultural rate design adjustment.
- AECA's proposal to retain legacy TOU for 10 years for all agricultural customers.
- AECA's proposal to replace the monthly demand charge with a daily demand charge, calculated based on peak or part peak and maximum demand charges.
- AECA's proposal to interpret Public Utilities Code Section 744(c) to require rates for agricultural customers on TOU rates to be set at a discount from the system average rate.
- AECA's proposal for an optional rate for agricultural customers to support the daily renewable integration needs of the CAISO, designed to incentivize shifts in peak load demand similar to TOU rates.
- AECA's proposal for "account aggregation" that would allow multiple accounts held by an agricultural customer to aggregate demands across multiple accounts.
- AECA's proposal for PG&E to revise its forecasting model to include lagged Palmer Drought Severity Index as a driver, to update its model to capture Central Valley Project and State Water Project water allocations, and to replace Moody's agricultural index forecast with United States Department of Agriculture data.

- AECA's proposal for PG&E to modify its agricultural load forecast by forecasting wet, normal, and dry years and averaging these forecasts for a weighted average forecast.

Finally, CFBF proposed that agricultural customers be provided an interim bill credit if the customer was impacted by a public safety power shutoff (PSPS) event after the end of the calendar year. CFBF also proposed developing a more permanent PSPS bill credit proposal before PG&E's next GRC Phase 2 application. PG&E contested this proposal.

10.1. Agricultural Rate Design Settlement

On April 8, 2021, PG&E served and filed a motion seeking adoption of an Agricultural Rate Design Supplemental Settlement Agreement (ARD settlement). The motion claimed to resolve all agricultural rate design issues in the current proceeding, with the exception of the CFBF proposal for a PSPS bill credit. The motion stated that the parties to the ARD settlement are AECA, CFBF, and PG&E. Because the parties serving testimony on agricultural rate design issues signed the ARD settlement, the ARD settlement is uncontested.

With respect to PG&E's uncontested proposals, the ARD settlement agreed that they are reasonable and should be approved. The ARD settlement also recommended that the Commission maintain the status quo for the Optimal Billing Period Program and Peak Day Pricing (PDP) provisions. The ARD settlement also recognized that the Commission revised the PDP hours for Summer 2022 in D.21-03-056.[312]

The ARD settlement recommended the creation of new optional agricultural rate Schedules AG-A3 and AG-B2 that reduce the summer off-peak

[312] Motion to adopt ARD settlement at 3.

energy charges below the electric bundled system average rate. This would be accomplished by widening the summer on-peak versus summer off-peak differential on a cents-per-kWh basis, such that total off-peak energy charges would be set one-tenth of a cent below the bundled system average rate.[313]

Out of concern for the impacts of potential marginal costs on certain members of the agricultural class, the ARD settlement proposed that changes in revenue allocation that impact the agricultural class should be capped at the "AG rate group level," such that the change in average rates for the three rate groups within the agricultural class should be set at the agricultural class average percentage change, which per the revenue allocation settlement shall not exceed 1.5 percent for bundled schedules, or 3.0 percent for DA/CCA schedules.[314]

With respect to agricultural sales forecasting, which parties agreed required reform, the ARD settlement proposed the following changes to PG&E's methodology:

- Inclusion of both the current[315] and lagged Palmer Drought Severity Index (PDSI) variables in PG&E's sales and customer accounts forecasting regression model, beginning with the forecast that will be proposed in PG&E's 2023 ERRA Forecast proceeding, which will be filed in June 2022.
- For the November Update of the ERRA Forecast proceeding, PG&E will revise the sales forecast for the agricultural customer class by using the most recent PDSI information available as of mid-July of the filing year.

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313 Motion to adopt ARD settlement at 4.

314 Motion to adopt ARD settlement at 5.

315 The "current" PDSI variable will be based on PDSI data available in February of the year of ERRA filing.

- PG&E will use United States Department of Agriculture Economic Research Service historical statewide Net Cash Income as regressors in its models, beginning with the forecast that will be proposed in PG&E's 2023 ERRA Forecast proceeding.
- PG&E will use an agricultural price of electricity as a regressor in its sales model. For modeling purposes, the historical value of this price will be determined by the contents of filed Annual Electric True-up documents discounted by historical consumer price index figures.
- PG&E will use an internal version of the customer billings model presented in AECA's testimony when generating agricultural sales forecasts.[316]

Notwithstanding the modifications to PG&E's sales forecast methodology described above, the ARD settlement granted that implementation of these modifications would be subject to the following conditions:

- A statistical fit is not noticeably worse than the existing model, or another sales forecasting model that may be developed in the future.
- The modifications do not cause the longer-term forecast values to be demonstrably out of sync with current forecast and understanding.
- The data remains available in a timely manner.[317]

In consideration of the modifications to PG&E's sales forecast methodology, AECA agreed to withdraw its proposal for developing the annual ERRA Forecast load forecast using a weighted average of wet, normal, dry year conditions. Furthermore, PG&E will, no earlier than March of 2024, perform a lookback study to assess whether the new variables improved the forecast. If the

[316] Motion to adopt ARD settlement at 6-7.

[317] Motion to adopt ARD settlement at 7.

modifications to the methodology result in an improvement, then they would be retained. If no improvement is discovered, PG&E is allowed to eliminate the modifications from its regression model.[318]

The ARD settlement proposed to dispose of certain issues raised by AECA by agreeing that they should not be decided in this case but instead should be considered in a future PG&E GRC Phase 2 application. These issues are: a new 10-year legacy TOU period, a springtime rate or balancing account adjustment, daily demand charges, and an account or demand aggregation program.[319]

Finally, the ARD settlement proposed that the unbundling of the PCIA from the generation component of bundled rates be designed as a flat PCIA rate, not differentiated by season or TOU period, consistent with the PCIA rate design for Direct Access and Community Choice Aggregation customers. The PCIA rate for bundled customers would use the most recent vintage of the PCIA rate.[320]

10.2. Application of Article 12 of the Rules

The Commission has long favored the settlement of disputes. Article 12 of the Rules generally concerns settlements. Pursuant to Rule 12.1(d), 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 uncontested. The ARD settlement is uncontested.

The motion to adopt the ARD settlement claimed that it should be found to be reasonable in light of the whole record as it adopts compromises between

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[318] Motion to adopt ARD settlement at 8.

[319] Motion to adopt ARD settlement at 8.

[320] Motion to adopt ARD settlement at 9.

the parties on disputed issues that are within the range of litigated positions.[321] Attachment 2 to the ARD settlement reveals that the settlement's terms are indeed within the range of litigated positions, and therefore this decision finds that the ARD settlement is reasonable in light of the whole record.

The motion to adopt the ARD settlement claimed that the settlement should be found to be consistent with the law "as it complies with all applicable statutes and prior Commission decisions" including Public Utilities Code Section 451.[322] No party disputed that the ARD settlement complied with all applicable statutes and prior Commission decision, and therefore this decision finds that the ARD settlement is consistent with the law.

The motion to adopt the ARD settlement claimed that the settlement should be found to be in the public interest because it represents a reasonable compromise of litigated positions, avoids further litigation on ARD issues in this proceeding, and "provides more certainty to customers regarding their present and future costs."[323] This decision agrees with these assertions, and therefore finds that the ARD settlement is in the public interest.

Because the ARD settlement complies with the requirements of Rule 12.1 as described above, this decision holds that it is reasonable to adopt the ARD settlement in its entirety. PG&E shall implement the terms of the ARD settlement as soon as practicable.

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[321] Motion to adopt ARD settlement at 12.

[322] Motion to adopt ARD settlement at 13.

[323] Motion to adopt ARD settlement at 13.

10.3. Bill Credit for Agricultural Customers Impacted by PSPS Events

The ARD settlement did not resolve one issue related to agricultural rate design – CFBF's proposal for a bill credit for agricultural customers impacted by PSPS events.

CFBF argued that agricultural customers taking service on TOU rates face unique challenges when impacted by a PSPS event. They claimed that because a PSPS event may cut off electricity for several hours or days, agricultural customers "may be forced to irrigate their fields outside of the schedule otherwise utilized in their operations, thereby increasing their costs of irrigation compared to the costs under their typical irrigation schedules" and that "[t]his could result in much higher usage than would be normally expected during peak price hours if no PSPS were called, which, in turn, could result in much higher bills for those agricultural customers."[324]

CFBF proposed that impacted agricultural customers should receive a bill credit related to their actions 1) during the 24-hour period prior to the PSPS event and 2) the 168 hours after the PSPS event. As an interim mechanism, CFBF proposed that customers should have all energy usage during those two periods (i.e., before the PSPS event and after the PSPS event) charged at off-peak energy rates instead of their otherwise applicable time-of-use energy rates. CFBF also sought to avoid charging an impacted customer any monthly maximum demand charges and monthly maximum on-peak demand charges during these pre- and post-PSPS event periods. The difference in costs between the revised charges

[324] Exh. CFBF-01 at 2.

and the otherwise applicable tariff would be refunded to customers in the form of a bill credit, under CFBF's proposal.[325]

Finally, CFBF recommended that the Commission order PG&E to convene a working group consisting of PG&E and other interested parties following the effective date of this decision to develop a long-term bill credit mechanism for agricultural customers impacted by PSPS events, which PG&E would proposed in its next GRC Phase 2 proceeding.[326]

PG&E rejected CFBF's proposal as inappropriate and illogical. PG&E asserted that the nature of PSPS events result from climatic conditions that are beyond PG&E's control.[327] Given this lack of control, PG&E believed that it would be inappropriate to credit customers in a way that either penalizes PG&E financially, or passes the costs on to other PG&E ratepayers not receiving the bill credit.[328] In particular, PG&E noted that "[n]owhere in PG&E's tariffs or terms of service is [] a guarantee against interruption of service provided, and to start giving it in connection with PSPS public safety related operations is not reasonable."[329]

PG&E also argued that the principle of statewide consistency supports the rejection of CFBF's bill credit proposal. PG&E pointed out that the proposal only targets PG&E, and even then only PG&E's agricultural class would be eligible for the bill credit. PG&E questioned whether this was appropriate given the impact

[325] Exh. CFBF-01 at 6-7.

[326] Exh. CFBF-01 at 8.

[327] Exh. PG&E-07 at 13-9 ("PG&E does not undertake a PSPS event except in accordance with Commission approved guidelines, which are designed using indicia of extremely dangerous weather conditions that can result in jeopardy to public safety, life, and property").

[328] Exh. PG&E-07 at 13-7 to 13-8.

[329] Exh. PG&E-07 at 13-8.

of PSPS events on other customer classes both in PG&E's territory and the territories of the other large electrical corporations. PG&E recommended that, should the Commission wish to pursue this policy, it should implement an OIR to consider potential PSPS bill credits for all customer classes of all large electrical corporations.[330]

PG&E levelled additional criticisms of the bill credit proposal, including that it 1) is not cost-based, 2) creates perverse incentives to increase peak demand, 3) creates an unknown revenue shortfall, 4) does not account for generation charges for Direct Access or CCA customers, 5) does not account for NEM ratemaking treatment, and 6) fails to account for billing system implementation issues.[331]

In briefs, CFBF finalized its interim proposal that agricultural customers that are impacted by PSPS events would have all of their energy usage during the 24-hour period prior to the PSPS event and the 168 hours after the PSPS event charged at off-peak energy rates instead of their otherwise applicable time-of-use energy rates. In addition, CFBF proposed that the customer's monthly maximum demand and monthly maximum on-peak demand should not be changed because of the usage during these pre- and post-PSPS event periods. The difference in costs between the charges at the otherwise applicable tariff and the off-peak rates for the two time periods would be refunded to customers in the form of a bill adjustment. The bill adjustment would be applied on an annual

[330] Exh. PG&E-07 at 13-9.

[331] Exh. PG&E-07 at 13-9 to 13-26.

basis.[332] Any revenue shortfall that would result from the bill adjustment would be recovered from the agricultural class.[333]

EUF criticized CFBF's proposal as unfair, given that it only provided a bill adjustment for agricultural customers and not for all of PG&E's customers. PG&E and EUF agreed that if there was to be Commission-sanctioned bill relief for customers impacted by PSPS events, that relief should be applied to all utility customers and should be considered in the appropriate cross-utility proceeding before the Commission.[334] PG&E urged the Commission to reject CFBF's proposal on this ground, in addition to several others including lack of cost causation, administrative burden, and procedural impropriety.[335]

As pointed out by PG&E, there is a proceeding at the Commission to consider the issue of utility execution of PSPS events in 2019 – Investigation (I.) 19-11-013. That proceeding's ultimate decision – D.21-06-014 – was issued by the Commission on June 7, 2021. That decision considered recommendations from the parties that the Commission adopt a monetary remedy to compensate customers affected by the 2019 PSPS events, through bill credits or PSPS-related cost disallowances. That decision also noted that PG&E voluntarily provided bill credits to some customers affected by its 2019 PSPS events.[336] The Commission took heed of this recommendation, finding that the large electrical corporations failed to reasonably identify, evaluate, weigh, and report public risks resulting from PSPS events, and therefore held that a monetary remedy was appropriate.

[332] CFBF OB at 5.

[333] PG&E OB at 98.

[334] PG&E OB at 98.

[335] PG&E OB at 99-105.

[336] D.21-06-014 at 59.

Noting that it had the authority to authorize bill credits to compensate for the failures of the electrical corporation, that decision declined to do so. Instead, it choose to craft what it called a "ratemaking remedy" that prevents the large electrical corporations from recovering from customers any undercollections of authorized revenue requirement due to the lower volumetric sales caused by a power shutoff during a PSPS event. This remedy would affect all utility customers and would not be limited to a single class of customers or group of affected customers. D.21-06-014 theorized that this remedy would have the effect of lowering customer rates overall in proportion to the duration and scope of a PSPS event.[337]

Because the Commission recently considered the question of whether to compensate customers affected by a PSPS event with a bill credit, and declined to do so in favor of a different remedy affecting rates generally for all customers, it would be improper for this decision to reverse that ruling by adopting CFBF's proposal in light of the full record considered by I.19-11-013 and the specific focus of that proceeding on the proper Commission response to the PSPS events executed by the large electrical corporations.

11. Commercial and Industrial Rate Design

In this proceeding, PG&E proposed several changes to its rate designs for commercial and industrial (C&I) customers. However, PG&E's main objective in this proceeding was to retain the rate designs adopted in PG&E's previous GRC Phase 2 proceeding and approved in D.18-08-013. Therefore, PG&E did not propose changes to C&I rate TOU periods or seasons, or to the overall structure of the current C&I rate designs, including customer fixed charges.

[337] D.21-06-014 at 60-61, OP1.

Notwithstanding this desire to generally seek consistency between existing C&I rate designs and those proposed in this proceeding, PG&E did propose certain changes to its C&I rate designs, including: 1) changes to Schedule B-6 to create greater differentiation between peak and off-peak rates in 2022, 2) elimination of the voluntary TOU meter charges on legacy rate Schedules A-6 and E-19 voluntary, 3) revised generation charges for Schedule SB, and 4) adjustment to winter generation energy rates for Schedules E-19, E-19V, E-20, B-19, B-19V, and B-20 so that the Super Off Peak (SOP) rate is not less than the PCIA.[338]

Testimony responding to PG&E's proposals on C&I rate design issues was served on October 23, 2020, by Cal Advocates, and on November 20, 2020 by SBUA, CLECA, FEA, EPUC, CALSLA, Joint CCAs and SEIA. These parties agreed with PG&E's proposals in many respects, but they also sought some changes. These positions contrary to PG&E's proposals included:

- SBUA wished to see changes to the SOP period at the earliest opportunity, consistent with adequate outreach.[339]
- SBUA recommended that Schedule B-6 have its TOU differentials increased to full cost.[340]
- CLECA argued that the interclass allocation of the PCIA should reflect adopted generation allocation factors, rather than simply relying on the latest PCIA vintage.[341]
- Joint CCAs believed that certain changes should be made to PG&E's proposed presentation of the PCIA value on tariff sheets for bundled customers.[342]

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[338] Exh. PG&E-03 at 4-3 and 4-4.

[339] Exh. SBUA-01 at 5-6.

[340] Exh. SBUA-01 at 17.

[341] Exh. CLECA-01 at 51.

[342] Exh. Joint CCAs-01 at 10.

- SEIA and SBUA recommended that the Commission require PG&E to seek revisions to their transmission rates at FERC. Specifically, SEIA sought to align PG&E's transmission rates with rate design policies already established by the Commission, resulting in transmission rates that are not so heavily weighted toward non-coincident demand charges.[343] SBUA also proposed interim adjustments to transmission rates before FERC consideration of any PG&E proposals.[344]
- SBUA proposed replacing non-coincident demand charges with flat per kWh rates, and replacing time-varying demand charges with volumetric TOU rates.[345]
- With respect to Schedule B-20, several parties suggested increasing the size of demand charges while reducing volumetric rates in comparison to the C&I rates proposed by PG&E.[346]
- CLECA recommended revising the calculation of Option R rates by using billing determinants derived from Option R customers to calculate the rates, rather than billing determinants derived from all customers on a given rate.[347]
- SEIA proposed replacing the Option R rates with new Option C rates, that would generally keep the Option R rate design but include full EPMC TOU differentials, and expand the design to Schedule B-10 (effectively creating a new Schedule C-10).[348]

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[343] Exh. SBUA-01 at 12; Exh. SEIA-01 at 39-42 ("PG&E should recover 27 percent of its transmission costs through peak-related charges. This direction should apply to all of PG&E electric rates"). *See also* Exh. SBUA-02 at 2-3. This issue was previously considered and disposed of in this decision.

[344] Exh. SBUA-01 at 13.

[345] Exh. SBUA-01 at 28-29.

[346] *See, e.g.,* Exh. CLECA-01 at 60-61.

[347] Exh. CLECA-01 at 61-63.

[348] Exh. SEIA-01 at 35.

11.1. Commercial and Industrial Rate Design Settlement

PG&E served a motion for Adoption of Commercial and Industrial Rate Design Supplemental Agreement (C&I rate design settlement) on April 13, 2021. The motion claimed that the C&I rate design settlement was uncontested, and that it resolved all of the differences between PG&E's original proposals and the parties' recommended changes, with the exception of transmission rate design issues.

The C&I rate design settlement recommended adoption of several uncontested proposals made by PG&E in its testimony. These uncontested issues include: 1) PG&E's legacy rate design proposal, 2) retaining the existing Small Light and Power eligibility threshold of 75 kW, 3) rate design for Schedules B-1, B-15, E-CARE, SB, and TC-1, 4) elimination of voluntary TOU meter charges for Schedules A-6 and E-19V, 5) retaining the existing Food Bank discount, and 6) rules for changing rates between GRC Phase 2 proposals.[349]

The C&I rate design settlement proposed the following changes to the rate design of Schedule B-6: 1) Summer Peak to Off Peak maximum differential of $0.25763, 2) Winter Peak to Off Peak maximum differential of $0.04360, and 3) Winter Peak to Super Off Peak maximum differential of $0.07968.[350] For Schedules B-19, B-19V, and B-20 the settlement determined that the peak generation demand charge should be adjusted in line with the generation marginal costs adopted by this decision.[351]

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349 Motion to adopt C&I rate design settlement at 5.

350 Motion to adopt C&I rate design settlement at 5-6.

351 Motion to adopt C&I rate design settlement at 6.

The C&I rate design settlement formalized a number of eligibility requirements for Option R customers on Schedules B-19, B-19V, B-20, E-19, E-19V, and E-20, and developed rules for calculating and recovering revenue shortfalls from such customers. The total participation cap for Option R across those C&I schedules is recommended to be 600 MW.[352] Furthermore, the settlement proposed a new Option R for Schedule B-10 customers that would not have any eligibility requirements. Revenue shortfalls resulting from B-10R customer usage would be collected from other B-10 customers regardless of their voltage level.[353]

With respect to the PCIA, the C&I rate design settlement recommended that the PCIA for bundled customers be separated from bundled generation rates based on the most current vintage PCIA and shall be a flat rate not differentiated by season or TOU to ensure rate comparability with Community Choice Aggregator and Direct Access rates. The PCIA would be separately displayed on the relevant tariff sheets for C&I customers.[354]

The C&I rate design settlement also requires PG&E to provide illustrative rates in its next GRC Phase 2 proceeding. First, PG&E will provide illustrative rates that convert TOU demand charges to TOU energy rates and non-coincident demand charges to flat energy rates for Schedules B-10, B-19, B-19V, and B-20 in its next GRC Phase 2 proceeding.[355] Second, PG&E will provide illustrative Option R rate designs based on the billing determinants for customers

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[352] C&I rate design settlement at 10-12.

[353] C&I rate design settlement at 13-14.

[354] C&I rate design settlement at 14.

[355] C&I rate design settlement at 9.

participating on Option R rates for each of its B-19 and B-20 Option R schedules that have at least 10 participating customers.[356]

11.2. Application of Article 12 of the Rules

The Commission has long favored the settlement of disputes. Article 12 of the Rules generally concerns settlements. Pursuant to Rule 12.1(d), 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 uncontested. The C&I rate design settlement is uncontested.

The motion to adopt the C&I rate design settlement claimed that it should be found to be reasonable in light of the whole record as it adopts compromises between the parties on disputed issues that are within the range of litigated positions.[357] Appendix 3 to the C&I rate design settlement reveals that the settlement's terms are indeed within the range of litigated positions, and therefore this decision finds that the C&I rate design settlement is reasonable in light of the whole record.

The motion to adopt the C&I rate design settlement claimed that the settlement should be found to be consistent with the law "as it complies with all applicable statutes and prior Commission decisions" including Public Utilities Code Section 451.[358] No party disputed that the C&I rate design settlement complied with all applicable statutes and prior Commission decision, and therefore this decision finds that the C&I rate design settlement is consistent with the law.

[356] C&I rate design settlement at 10.

[357] Motion to adopt C&I rate design settlement at 11.

[358] Motion to adopt C&I rate design settlement at 11.

The motion to adopt the C&I rate design settlement claimed that the settlement should be found to be in the public interest because it represents a reasonable compromise of litigated positions, avoids further litigation on settled C&I rate design issues in this proceeding, and "provides more certainty to customers regarding their present and future costs."[359] Appendix 3 to the motion to adopt the C&I rate settlement describes how the settled positions lie between the litigated positions of the parties. For example, PG&E and CLECA disagreed on how to unbundle the PCIA from bundled generation rates. PG&E argued that the PCIA should simply be set to the latest PCIA vintage, while CLECA argued that the interclass allocation of the PCIA should reflect adopted generation allocation factors, rather than simply relying on the latest PCIA vintage. The C&I rate design settlement adopted a compromise position where the bundled PCIA would initially be set equal to the most recent vintage PCIA but the adopted allocation for generation will be used to set going-forward PCIA rates.[360]

This decision agrees that the C&I rate design settlement adopts compromise positions between the litigated positions of the parties, as evidenced by Appendix 3 to the settlement itself, and therefore represents a reasonable compromise that avoids further litigation on the issues and provides certainty to commercial and industrial customers regarding their future rate designs. For these reasons this decision finds that the C&I rate design settlement is in the public interest.

Because the C&I rate design settlement complies with the requirements of Rule 12.1 as described above, this decision holds that it is reasonable to adopt the

[359] Motion to adopt C&I rate design settlement at 11.

[360] Motion to adopt C&I rate design settlement, Appendix 3 at 1.

C&I rate design settlement in its entirety. PG&E shall implement the terms of the C&I rate design settlement as soon as practicable.

12. E-CREDIT Issues

PG&E's fourth status report on settlement negotiations contained the following statement regarding E-CREDIT issues:

> The parties agree that PG&E's proposals for Fees for Services to Community Choice Aggregation and Direct Access Electric Service Providers (Exhibit (PG&E-3), Chapter 8) were unopposed. The parties also acknowledged that, while the rate values proposed by PG&E for Schedule E-CREDIT (Exhibit (PG&E-4, Appendix J) were based on PG&E's proposed Revenue Cycle Service Marginal Cost, the methods PG&E used to set the E-CREDIT values were reasonable. Further, that if those methods were applied based on the final approved Revenue Cycle Service Marginal Cost, reasonable rate values for Schedule E-CREDIT would result. The parties agree that, on this basis, Schedule E-CREDIT is also unopposed.[361]

Because E-CREDIT issues appear to be unopposed, this decision finds that PG&E's proposals on E-CREDIT issues are reasonable and should be adopted.

13. Summary of Public Comment

As of September 2, 2021, 125 public comments were posted to the Commission's docket card webpage for this proceeding. Pursuant to Rule 1.18(b), the following summary of relevant written comment is provided. Almost all commenters opposed the rate increases that they believe were proposed by PG&E in this proceeding, in particular the proposed reductions to gas and electric baselines. These comments predated the filing of the residential rate design settlement, which adjusted PG&E's original baseline quantity proposals. Some commenters expressed a desire for revised residential rate

[361] PG&E's fourth status on settlement negotiations at 9.

designs that would financially benefit their own particular electricity usage profile. Other commenters complained about the opacity of communications regarding this proceeding from PG&E, and their inability to determine the reasons for some of the charges appearing on their bills.

14. Comments on Proposed Decision

The proposed decision of the ALJs 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 ______________________________.

15. Assignment of Proceeding

Genevieve Shiroma is the assigned Commissioner and Patrick Doherty and Carolyn Sisto are the assigned Administrative Law Judges in this proceeding.

Findings of Fact

1. Marginal customer access occurs whenever a customer moves from one location to another, or when a new customer moves into a location with existing access equipment.

2. Existing customer access equipment has value as facilitating incremental (and therefore marginal) customer access.

3. Existing customer access equipment does have some value, even if only as scrap, and a utility continues to pay for its existing customer access equipment through operations and maintenance, as well as holding the equipment on its books as an asset.

4. Existing customer access equipment that may be used for customer access is plainly not new and should not be valued as such.

5. PG&E's use of several years of data smooth out potential annual variations that might skew the performance of the RCS model if only a single year's worth of data is used.

6. The heterogenous nature of RCS costs means that the use of a blanket five percent discount, apparently calculated without a specific methodology in mind, would likely not accurately reflect changes to actual RCS costs that could be observed over time.

7. The parties generally agreed with PG&E's methodology for calculating MEC.

8. Any excess RPS resources that PG&E may have at its disposal are not guaranteed to apply to marginal energy purchases that it may make in the future.

9. Each marginal purchase of energy by PG&E may involve the purchase of additional RPS-compliant energy.

10. There are apparent issues around transparency, reproducibility, accessibility, and parties' abilities to analyze PG&E's PCAF and FLT data.

11. As a matter of state policy, it is unlikely that substantial investments in new natural gas generation will be made in California in the near future, even if its net cost were lower than that of energy storage.

12. PG&E includes the cost of electricity used by the battery in the MGCC calculation through its use of the EGM variable.

13. Requiring the cost of electricity generation capacity to be separately included in the MGCC calculation would amount to double-counting the cost of supplying the energy storage unit with electricity.

14. PG&E will procure additional generation capacity between now and 2026.

15. The sole use of test year cost data to generate an MGCC figure is inconsistent with Commission precedent and may send an inaccurate price signal.

16. The use of a six-year average helps to level out annual fluctuations in prices and therefore is a superior basis for calculating MGCC.

17. PG&E bases its energy storage cost of capital calculation on the dataset used in the IRP proceeding, with certain modifications.

18. PG&E's energy storage capital cost estimates are generally consistent with the Commission's approved process for long-term generation procurement planning.

19. PG&E's energy storage capital cost calculations fall between NREL and Lazard estimates, and this supports a finding that PG&E's estimated capital costs are reasonable.

20. PG&E's forecasted 43 percent cost decline in energy storage capital costs is a reasonable estimate given the substantial uncertainty that exists with respect to future energy storage costs.

21. PG&E based its financial assumptions for the cost of energy storage on the IRP model already approved and utilized by the Commission in planning for future generation procurement.

22. PG&E's estimates of future EGM values reflect empirical observations of the behavior of energy storage as arbiters of energy resources across different hours of the day.

23. PG&E's proposed battery lifetime, augmentation, and VOM calculations are reasonable.

24. PG&E's proposed battery lifetime, augmentation, and VOM calculations are consistent with the Commission's approved IRP modelling process.

25. The cost of property taxes has not been appropriately included in PG&E's MGCC calculation.

26. No party disputed PG&E's proposed short-run avoided capacity costs.

27. PG&E's proposed energy and demand-related line loss factors were uncontested.

28. It is reasonable to assume that capacity-related transmission projects are tied to demand and load growth unless demonstrated otherwise given that reliability concerns may logically be tied to increases in peak customer demand.

29. Capacity-related transmission projects are likely to be related to growth in demand (particularly peak demand).

30. PG&E's proposal to disaggregate delivered and received loads for the purpose of calculating cost of service is not directly opposed by any party for use in this proceeding.

31. PG&E's proposal to disaggregate delivered and received loads creates more accurate calculations of cost of service for use in a GRC Phase 2 proceeding.

32. Cal Advocates and SEIA expressed discomfort in applying PG&E's cost of service methodology in the future without further study.

33. The RA settlement impacts the litigated positions of the parties in certain open proceedings.

34. The terms of the RA settlement are compromise positions between the various positions taken by the parties in their testimony.

35. No party disputed that the RA settlement was consistent with the law and no inconsistency with the law is apparent.

36. The approved marginal costs and the RA settlement together lead to average rate impacts of one and half percent or less in either a positive or negative direction for any given class.

37. All of PG&E's customers benefit from PG&E's efforts to mitigate the wildfire risk posed by its distribution network, and wildfire mitigation work is normatively distinct from PG&E's ordinary distribution investments.

38. Many of the parties active in R.12-06-013, in which D.15-07-001 was issued, are signatories to the residential rate design settlement and therefore they were aware of the implications of proposing an effective modification of D.15-07-001 in the residential rate design settlement and agree that the statutory obligations surrounding an inclining block rate structure for Schedule E-1 continue to be fulfilled.

39. A.16-06-013 and the omnibus residential rate reform rulemaking (R.12-06-013) closed years ago without adopting a residential fixed charge based on the cost categories identified by D.17-09-035.

40. The residential rate design settlement's proposed electric baseline quantities represent significant decreases from previously approved baseline quantities and therefore will result in adverse bill impacts for those customers that currently use their full allotment of baseline electricity.

41. The residential rate design settlement's use of caps to limit the impact of PG&E's originally proposed reductions to residential electric baseline quantities mitigates the concern regarding bill impacts that would result in such reductions.

42. The terms of the residential rate design settlement are compromise positions between the various positions taken by the parties in their testimony.

43. The terms of the streetlight rate design settlement are compromise positions between the various positions taken by the parties in their testimony.

44. The terms of the EDR settlement are compromise positions between the various positions taken by the parties in their testimony.

45. The terms of the ARD settlement are compromise positions between the various positions taken by the parties in their testimony.

46. The terms of the C&I rate design settlement are compromise positions between the various positions taken by the parties in their testimony.

47. Disposition of E-CREDIT issues, as reflected in PG&E's filings, is unopposed.

Conclusions of Law

1. Marginal cost-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.

2. As a matter of fairness, those customers and customer classes that are less expensive to serve should enjoy the benefit of that status, and those customers that cost more to serve should see that status reflected in their rates.

3. Existing access equipment should be valued as providing the ability to incrementally provide customer access to the grid.

4. Once an old customer terminates utility service the existing equipment transforms into equipment that is waiting to provide incremental access, and a new customer that uses existing equipment should appropriately assume the marginal cost of that asset – both its operational costs and its depreciated value.

5. The Commission should not assign marginal costs (and therefore marginal cost revenues) that are not aligned with the actual value of marginal equipment.

6. It is not unreasonable to require PG&E to forecast all of its MDCC investments at the DPA level because doing so would enable parties to better understand the total forecasted investments that are driving the MDCC in each

of the DPAs, instead of relying on the larger MDCC investments that might be forecasted for a particular DPA.

7. It is reasonable to adopt PG&E's proposed methodology for calculating MEC, subject to certain modifications.

8. It is reasonable to require the use of a non-time-differentiated REC adder equal to a REC value times the RPS percentage in a given year.

9. It is reasonable to seek temporal consistency among inputs to PG&E's MEC calculations.

10. It is appropriate for PG&E to use the MPB used in PG&E's 2021 ERRA proceeding as set forth in PG&E's ERRA testimony served in July 2020 to calculate the REC value.

11. It would be inappropriate to use a natural gas plant as the basis for a system-level MGCC calculation.

12. It is reasonable to use a stand-alone, four-hour energy storage system as the capacity resource when calculating the MGCC for PG&E in this proceeding.

13. It is reasonable to use a six-year average basis for calculating MGCC.

14. The long-term costs that are incurred in 2021 for energy storage should be used to generate the 2021 cost figures used in the six-year average MGCC calculation.

15. It is appropriate to use the IRP dataset to help set PG&E's MGCC in this proceeding given that it has already been vetted by the Commission to help plan for long-term generation capacity.

16. It is reasonable to adopt PG&E's proposed estimates of the cost of capital for energy storage as it applies to the MGCC calculation in this proceeding.

17. PG&E's financial assumptions for the MGCC cost of capital calculation, with the exception of property tax inputs, are reasonable and should be approved.

18. IRP assumptions are an appropriate basis for calculating the MGCC given their role in planning future generation capacity procurement by the Commission.

19. PG&E's EGM calculations should be adopted.

20. PG&E's short-run avoided capacity cost figure is reasonable.

21. PG&E's energy and demand-related line loss factor calculations, as used to create the 2021 MEC by voltage levels, shown in Exhibit PG&E-2A, are reasonable and should be approved.

22. PG&E's long-run avoided capacity cost of $102.53/kilowatt-year in 2021, and PG&E's six-year discounted average MGCC in 2021 of $68.56/kilowatt-year for 2021-2026 are reasonable and should be approved.

23. It is reasonable to adopt SEIA's proposed MTCC of $52.45 per kW-year on the presumption that approximately 27 percent of PG&E's near-term planned transmission investments are related to capacity needs and therefore will be impacted by customer reductions in peak demand in response to marginal cost signals.

24. Consistent with the Commission's preference for marginal cost-based rate design, PG&E's transmission rates should be time-differentiated to reflect those costs.

25. It is reasonable to adopt PG&E's proposed cost of service methodology for use in this proceeding only.

26. The RA settlement is reasonable in light of the whole record.

27. The RA settlement is consistent with the law.

28. The rate and bill impacts of the RA settlement are reasonable.

29. It is desirable to reallocate PG&E's wildfire mitigation costs away from a strict distribution cost allocation, and to more fairly distribute those costs to all of PG&E's customers.

30. The RA settlement is in the public interest.

31. The resolution of the Schedule E-1 issue in the residential rate design settlement does not comply with all previous Commission decisions because it seeks to effectively modify the D.15-07-001 holding that prices for Tier 2 electricity should be 25 percent higher than prices for Tier 1 electricity.

32. The design of the fixed charge for E-ELEC is intended to further state policy goals related to decarbonization and therefore has a particular policy purpose that may justify any dissonance with previous Commission decisions regarding the application of EPMC to residential fixed charges.

33. The findings and conclusions in D.17-09-035 should be applied only in the context of A.16-06-013.

34. PG&E's exclusion of medical baseline customers from E-ELEC and EV2, while apparently justified by the current understanding of the requirements of the medical baseline program, is contrary to state policy goals to incent residential electrification and electric vehicle adoption.

35. The residential rate design settlement is reasonable in light of the whole record, complies with the law, and is in the public interest.

36. The streetlight rate design settlement is reasonable in light of the whole record, complies with the law, and is in the public interest.

37. The potential development of a dimmable streetlight rate design and program should be expeditiously pursued under the SSA's terms, and disputes between parties should not unnecessarily interfere with such development.

38. The EDR settlement is reasonable in light of the whole record, complies with the law, and is in the public interest.

39. The ARD settlement is reasonable in light of the whole record, complies with the law, and is in the public interest.

40. The C&I rate design settlement is reasonable in light of the whole record, complies with the law, and is in the public interest.

41. PG&E's proposals on E-CREDIT issues are reasonable and should be adopted.

42. The proposed decision in this matter should be served on the service list of R.12-06-013 in order to provide parties to that proceeding an opportunity to comment on the modification of D.15-07-001 made by the provisions of the residential rate design settlement in this proceeding.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company shall use the Real Economic Carrying Cost (RECC) method to calculate its Marginal Connection Equipment Costs in determining revenue allocation and rate design and shall modify its RECC methodology so that it accounts for the remaining lives of the assets in place and the differentials in customer growth rates. New connection equipment may be valued using the RECC method, but existing equipment shall be valued using the "replacement cost new less depreciation" method as described by the Agricultural Energy Consumers Association in its briefing.

2. Pacific Gas and Electric Company shall utilize its proposed methodology for calculating Revenue Cycle Services costs in determining revenue allocation and rate design.

3. Pacific Gas and Electric Company shall utilize its proposed methodology for calculating marginal distribution capacity costs in determining revenue allocation and rate design.

4. Pacific Gas and Electric Company shall produce an accurate forecast of sub-$1 million marginal distribution capacity cost investments for each of its distribution planning areas for its next General Rate Case Phase 2 application.

5. Pacific Gas and Electric Company (PG&E) shall modify its method used to calculate incremental load growth as it relates to marginal distribution capacity cost by calculating only the absolute positive changes, and PG&E shall also update its investment allocation factors for discounted total investment method calculations as recommended by the Public Advocates Office at the California Public Utilities Commission.

6. Pacific Gas and Electric Company (PG&E) shall utilize its proposed methodology for calculating marginal energy costs in calculating revenue allocation and rate design, except that PG&E shall use a renewable energy credit (REC) value of $17.35/megawatt-hour when calculating the REC adder value to be applied during this General Rate Case cycle.

7. Pacific Gas and Electric Company shall, no later than July 2022, host a workshop to consider various methods to measure and reduce inter-annual variability in its Peak Capacity Allocation Factor and Final Line Transformer cost allocation results, including use of multiple years in the analyses and weather normalization of loads.

8. Pacific Gas and Electric Company (PG&E) shall construct a representative sample of Final Line Transformer (FLT) loads, which will (i) reduce the FLT dataset to a more manageable size and enable PG&E to make adjustments to reduce inter-annual variability, and (ii) include the representative sample as part

of its served workpapers in support of its opening testimony in its next GRC Phase 2 application.

9. Pacific Gas and Electric Company shall utilize a long-run avoided capacity cost of $102.53/kilowatt-year in 2021, and six-year discounted average marginal generation capacity cost (MGCC) in 2021 of $68.56/kilowatt-year for 2021-2026 in calculating its MGCC to be used in calculating revenue allocation and rate design, subject to the inclusion of a property tax adder to be considered and approved by a Commission decision in a later phase of this proceeding.

10. Pacific Gas and Electric Company shall utilize the Solar Energy Industries Association's proposed marginal transmission capacity cost of $52.45 per kilowatt-year in calculating revenue allocation and rate design.

11. Pacific Gas and Electric Company shall utilize its proposed cost of service methodology in calculating marginal energy and distribution costs to be used in calculating revenue allocation and rate design in this proceeding only.

12. Pacific Gas and Electric Company (PG&E) shall complete additional analysis to support the inclusion of received loads in subsequent proceedings that includes, but is not limited to, scenarios that examine the potential impacts of increases in received loads on revenue allocation. These scenarios should be based on forecasts of net energy metering penetration growth. PG&E shall provide this additional analysis in its next General Rate Case Phase 2 application to support the potential inclusion of received loads in its cost of service methodology in that future proceeding.

13. Pacific Gas and Electric Company (PG&E) shall serve a notice on the service list of Application (A.) 20-09-019, A.21-02-020, and A.18-03-015 informing the service list members of the impacts on the revenue allocation settlement and how it affects PG&E's litigated position. PG&E shall ensure through procedural

communications that the assigned administrative law judge and Commissioner for each proceeding are aware of the impacts of the revenue allocation settlement on the litigated position of PG&E in the proceeding.

14. Pacific Gas and Electric Company shall implement the provisions of the revenue allocation settlement as soon as practicable.

15. Pacific Gas and Electric Company shall propose an expansion of Schedule E-ELEC and Schedule EV2 eligibility to include medical baseline customers in a Tier 3 advice letter filed with the Commission's Energy Division no later than 12 months after the effective date of this decision.

16. Pacific Gas and Electric shall implement the provisions of the residential rate design settlement as soon as practicable.

17. Pacific Gas and Electric shall implement the provisions of the streetlight rate design settlement as soon as practicable.

18. Pacific Gas and Electric shall implement the provisions of the economic development rate settlement as soon as practicable.

19. Pacific Gas and Electric shall implement the provisions of the agricultural rate design settlement as soon as practicable.

20. Pacific Gas and Electric shall implement the provisions of the commercial and industrial rate design settlement as soon as practicable.

21. Application 19-11-019 remains open.

This order is effective today.

Dated ______________________________, at San Francisco, California.

APPENDIX A

APPENDIX A

Abbreviations, Acronyms, and Definitions

A.	Application
AB	Assembly Bill
ACC	Avoided Cost Calculator
ADU	Accessory Dwelling Unit
AECA	Agricultural Energy Consumers Association
ALJ	Administrative Law Judge
ARD Settlement	Agricultural Rate Design Supplemental Settlement Agreement
A/S	Ancillary Services
Base	Net master meter discount
BCAP	Biennial Cost Allocation Proceedings
BIP	Base Interruptible Program
CAISO	California Independent System Operator
Cal Advocates	Public Advocate's Office of Public Utilities Commission
CALSLA	California Street Light Association
CARE	California Alternate Rates for Energy
CCA	Community Choice Aggregator
CEEIA	Customer Energy Efficiency Incentive Account
CEMA	Catastrophic Events Memorandum Account
CFBF	California Farm Bureau Federation
CforAT	Center for Accessible Technology
C&I	Commercial and industrial
C&I rate design settlement	Commercial and Industrial Rate Design Supplemental Agreement
CLECA	California Large Energy Consumers Association
CMTA	California Manufacturers & Technology Association
COL	Conclusion of Law
CSI	California Solar Initiative
CT	Natural gas combustion turbine
D.	Decision
DA	Day Ahead
DACC	Direct Access Customer Coalition
DBA	Diversity Benefit Adjustment
DCRL	Demand Charge Rate Limiter
DMBA or minimum bill	Delivery Minimum Bill Amount
DPA	Distribution Planning Area
DR	Demand Response

DREBA	Demand Response Expenditures Balancing Account
DTIM	Discounted Total Investment Method
EDR	Economic Development Rate
EDR settlement	Economic Development Rate Supplemental Settlement Agreement
EE	Energy Efficiency
EGM	Energy Gross Margin
ENELX	Enel X North America, Inc.
EPIC	Energy Program Investment Charge
EPMC	Equal Percent of Marginal Cost
EPT	Equal percent of total revenue
EPUC	Energy Producers and Users Coalition
ERRA	Energy Resources Recovery Account
ES	Energy Storage
EUF	Energy Users Forum
EUS	Essential usage study
EV	Electric vehicle
FEA	Federal Executive Agencies
FERA	Family Electric Rate Assistance
FERC	Federal Energy Regulatory Commission
FHPMA	Fire Hazard Prevention Memorandum Account
FLT	Final Line Transformer
FRMMA	Fire Risk Mitigation Memorandum Account
GCAP	Gas Cost Allocation Proceeding
GRC	General Rate Case
HSM	Hazardous Substance Mechanism
HUC	High Usage Surcharge
IFC	Incremental Facility Charge
IRP	Integrated Resource Plan
Joint CCAs	Joint Community Choice Aggregators (East Bay Community Energy, Peninsula Clean Energy, Marin Clean Energy, Pioneer Community Energy, San Jose Clean Energy, Silicon Valley Clean Energy, and Sonoma Clean Power)
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LCOS	Levelized Cost of Service
LED	Light-emitting Diode
LLA	Line Loss Adjustment
M&E	Measurement and Evaluation
MCAC	Marginal Customer Access Costs

MCEC	Marginal customer equipment costs
ME&O	Marketing, Education and Outreach
MDCC	Marginal Distribution Capacity Costs
MEC	Marginal energy costs
MGCC	Marginal generation capacity costs
MGMA	Microgrids Memorandum Account
MPB	Market Price Benchmark
MTCC	Marginal transmission capacity cost
MW	Megawatt
MWh	Megawatt-hour
NCO	New Customer Only
NEM	Net energy metering
NERA	National Economic Research Associates
NPV	Net Present Value
NRDC	Natural Resources Defense Council
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
OB	Opening Brief
PCAF	Peak Capacity Allocation Factor
PCIA	Power Charge Indifference Adjustment
PDP	Peak Day Pricing
PDSI	Palmer Drought Severity Index
PG&E	Pacific Gas and Electric Company
PHC	Prehearing conference
POPP	Peak-to-off-peak
PPP	Public Purpose Program
PSPS	Public safety power shutoff
R.	Rulemaking
RA settlement	Revenue Allocation Supplemental Settlement Agreement
RB	Reply brief
RCS	Revenue Cycle Service
REC	Renewable energy certificate
RECC or rental	Real Economic Carrying Cost
Residential rate design settlement	Residential Rate Design Supplemental Settlement Agreement
RM	Regression Method
ROE	return on equity
RPS	renewables portfolio standard
RSP	Reference System Plan
RTM	Real-Time Market
Rules	Commission's Rules of Practice and Procedure

SB	Senate Bill
SBUA	Small Business Utility Advocates
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SEIA	Solar Energy Industries Association
SGIP	Self-Generation Incentive Program
SJV DAC	San Joaquin Valley Disadvantaged Community
SOP	Super Off Peak
SSA	Settlement on streetlight rate design issues
TBCC	Transitional Bundled Commodity Cost
TOU	Time-of-Use
TSM	Transformers, service drops, and meters
TURN	The Utility Reform Network
VMBA	Vegetation Management Balancing Account
VOM	Variable operations and maintenance
WACC	Weighted adjusted cost of capital
WECC	Western Electricity Coordinating Council
WMA	Western Manufactured Housing Communities Association
WMBA	Wildfire Mitigation Balancing Account
WMCE	Wildfire Mitigation and Catastrophic Event
WMPMA	Wildfire Mitigation Plan Memorandum Account

(END OF APPENDIX A)