Attachment 1 to Exhibit 1

Decision 18-11-027 November 29, 2018

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	Application 17-06-030

DECISION ON SOUTHERN CALIFORNIA EDISON COMPANY'S PROPOSED RATE DESIGNS AND RELATED ISSUES

TABLE OF CONTENTS

Title **Page**

TABLE OF CONTENTS
Con't.

Title **Page**

TABLE OF CONTENTS
Con't.

DECISION ON SOUTHERN CALIFORNIA EDISON COMPANY'S PROPOSED RATE DESIGNS AND RELATED ISSUES

Summary

This decision adopts rate designs and resolves related issues for Southern California Edison Company (SCE) raised in Application (A.) 17-06-030. This decision approves all of the settlements filed in this proceeding and creates two main forms of rate design for SCE's non-residential customers: Option D rates and Option E rates. This decision orders SCE to prepare a model of essential usage for its residential customers, sets an interim Family Electric Rate Assistance enrollment target of 50% for SCE, and directs SCE to prepare a dimmable streetlight rate and program for the Commission's consideration in its next General Rate Case Phase II application.

All issues contemplated in the scoping memo for this proceeding are resolved by filed settlements. There are no contested issues beyond the approved settlements for this decision to address. The proceeding is therefore closed.

1. Procedural Background

On June 30, 2017 SCE filed its General Rate Case (GRC) Phase II application. A utility's GRC Phase II proceeding generally establishes a utility's marginal costs, allocates its revenue, and designs rates for service provided to its customers. Several parties timely filed protests or responses to the application and automatically received party status, including the Office of Ratepayer Advocates (ORA),[1] the Agricultural Energy Consumers Association (AECA), the

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[1] Senate Bill (SB) 854, signed June 27, 2018, changed ORA's name to the Public Advocates Office of the Public Utilities Commission. Because the majority of this proceeding was conducted prior to the name change, this decision retains the name ORA in this decision.

California Large Energy Consumers Association (CLECA), the Solar Energy Industries Association (SEIA), the California Solar Energy Industries Association (CALSSA),[2] the California Farm Bureau Federation (CFBF), the Alliance for Retail Energy Markets and Direct Access Customer Coalition (AREM), the California Choice Energy Authority (CCEA), and the Utility Reform Network (TURN).

On August 3, 2017 the Federal Executive Agencies (FEA) filed a motion for party status which was granted on August 17, 2017. On August 31, 2017 the Energy Producers and Users Coalition (EPUC) filed a motion for party status which was granted on September 1, 2017. On October 13, 2017 Small Business Utility Advocates (SBUA) filed a motion for party status which was granted on October 18, 2017. On November 2, 2017 several organizations were granted party status at the pre-hearing conference: Western Manufactured Housing Communities Association (WMA), City of Lancaster, California Streetlight Association (CAL-SLA), Coalition for Affordable Streetlights (CASL), and Energy Users Forum (EUF). On March 13, 2018 the Natural Resources Defense Council (NRDC) filed a motion for party status which was granted on March 14, 2018. On June 14, 2018 the Santa Clara Valley Water Agency and the Rancho California Water District (jointly Renewable Energy Water Districts or REWD) filed a motion for party status which was granted on June 19, 2018.

On November 2, 2017 a prehearing conference (PHC) was held to determine parties, discuss the scope and schedule for the proceeding, and address other procedural matters. On November 22, 2017 a scoping memo was

[2] This acronym reflects the fact that the former California Solar Energy Industries Association is now known as the California Solar & Storage Association.

filed defining the scope and schedule for the proceeding. The scoping memo sets out the following issues to be addressed:

1. Marginal costs including refinements to calculating and distributing generation, distribution and customer marginal costs.
2. Revenue allocation.
3. Rate design including, but not limited to the following:
    a. Residential: baseline allocations, incorporation of time differentiated demand charges for distribution, grandfathered rate options, closing existing rates with legacy Time-of-Use (TOU) periods, optional TOU rates, and default TOU for Net Energy Metering (NEM) 2.0 customers.
    b. Non-residential: grandfathered rate options, consolidation of rate options, elimination of rates with historical super off-peak schedules, eligibility questions for agricultural customers, distribution pole mounted streetlight options, street lighting rate structure issues, economic development rate, food bank rate, small business issues, and rates focused on achieving the goals of the Commission's Distributed Energy Resources action plan (DER action plan).[3]
    c. Billing system limitations for any proposed rate structures.

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[3] The DER action plan is intended to align the Commission's vision and actions in shaping California's distributed energy resource (DER) future. The plan outlines a vision of DERs over the next several years, and serves as a roadmap in coordinating activities across multiple proceedings as California continues its commitment to greenhouse gas emission reduction and reform of utility distribution planning, investment, and operations. The plan serves as a guide for decision-makers, staff, and stakeholders as they facilitate proactive and forward-thinking DER policy. More information on the DER action plan is available at: http://cpuc.ca.gov/General.aspx?id=6442458159.

At the PHC held on November 2, 2017 SCE and the parties representing agricultural interests in this proceeding (AECA and CFBF) noted that the question of whether large on-the-farm agricultural operations were able to qualify for certain SCE agricultural and pumping (A&P) rates was an urgent issue that required formal resolution through a decision in this proceeding. On November 7, 2017 SCE, AECA, and CFBF properly noticed a settlement conference on this issue scheduled for November 14, 2017 and held the conference on that date. Representatives from SCE, CFBF, AECA, ORA, and TURN participated in the settlement conference. SCE, AECA, and CFBF filed a joint motion for approval of a settlement agreement on November 29, 2017. The settlement agreement on removal of the usage threshold for participation in SCE's A&P rates was not opposed, and the Commission approved the settlement in Decision (D.) 18-01-012 on January 11, 2018. That decision removed a monthly demand threshold for all SCE customers meeting the definition for "Agricultural Power Service" to allow them to take service on SCE's A&P rates.

ORA served its opening testimony on some of the remaining issues in the proceeding on February 16, 2018. Opening testimony was served by March 23, 2018 by TURN, SBUA, EUF, FEA, CLECA, EPUC, DACC, CALSSA, SEIA, AECA, CFBF, CASL, and CAL-SLA.

Four public participation hearings were held during March 2018. These public participation hearings occurred at Long Beach, California on March 19, Claremont, California on March 20, Fontana, California on March 21, and Visalia, California on March 22. Speakers at the hearings included small business owners, agricultural customers, residential customers, an elected official, and utility district representatives. Topics of discussion included general rate levels, revenue allocation, timing of peak and off-peak hours, customer bill presentation, subsidized rates for low-income residential customers, and undergrounding policy.

An initial settlement conference in this proceeding was held on April 6, 2018. Settlement conferences between the parties were held thereafter at various times. A separate settlement track to consider issues related to legacy Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) customers commenced subsequent to D.18-07-006, which ordered SCE and REWD parties to work collaboratively in this GRC Phase II proceeding to develop a mutually agreeable indifference mechanism for legacy RES-BCT customers. Settlement discussions on RES-BCT issues began on July 24, 2018. A motion by SCE and REWD parties to adopt a proposed indifference mechanism for the RES-BCT program was served on August 6, 2018. A motion by SCE and REWD parties to adopt a revised indifference mechanism for the RES-BCT program was served on September 28, 2018.

Motions to adopt settlements in this proceeding were served as described in the table below.

Settlement	**Date Served**
Economic Development Rate	May 30, 2018
Marginal Cost and Revenue Allocation (original motion)	July 3, 2018
Streetlight and Traffic Control	July 6, 2018
Marginal Cost and Revenue Allocation (amended motion)	July 13, 2018
Legacy TOU Rates for Solar Customers	July 23, 2018
Residential and Small Commercial Rate Design	July 30, 2018
Medium and Large Commercial Rate Design	August 3, 2018
Agricultural and Pumping Rate Design	August 3, 2018
RES-BCT Indifference Mechanism	August 6, 2018
Revised RES-BCT Indifference Mechanism	September 28, 2018

Evidentiary hearings were held on July 17 and 18, 2018, and August 9 and 10, 2018. The purpose of evidentiary hearings was to develop the record of this proceeding by examining panels of witnesses testifying on behalf of some of the settlements in this proceeding.

Opening briefs were scheduled to be served on August 27, 2018, although no parties filed briefs on that date. Reply briefs were scheduled to be served on September 4, 2018, although no parties filed reply briefs on that date, and upon that date the proceeding was considered submitted.

2. Standard of Review for Settlements

The Commission's standard of review for settlements is summarized in this section. This standard is applied to the settlements considered in this decision.

The Commission has long favored the settlement of disputes.[4] Article 12 of the Commission's Rules of Practice and Procedure generally concerns settlements. Pursuant to Rule 12.1(d) of the Commission's Rules of Practice and Procedure, the Commission will not approve a settlement unless it is found to be reasonable in light of the whole record, consistent with law, and in the public interest. This standard applies to settlements that are contested as well as uncontested. Where a settlement is contested, it will be subject to more scrutiny than an uncontested settlement.

3. Marginal Costs and Revenue Allocation

In this second phase of SCE's GRC the Commission is to determine the share of SCE's revenue requirement (*i.e.,* its forecasted costs) that should be paid for by each customer class. This process of assigning responsibility for shares of

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

SCE's forecasted costs among customer classes is known as "revenue allocation." Traditionally, the Commission has looked to each customer class's share of the utility's marginal costs as the starting point for determining the revenue allocation among classes for that utility, and then scaling from that marginal cost basis to collect the total revenue requirement.[5]

As defined by the scoping memo, SCE's marginal costs (including refinements to calculating and distributing generation, distribution and customer marginal costs) and revenue allocation amongst its customer classes are to be determined in this proceeding. A settlement among the parties on marginal costs and revenue allocation for SCE's customers (MC/RA settlement) was filed on July 3, 2018. An amended motion supporting the MC/RA settlement was filed on July 13, 2018. The MC/RA settlement is among the following parties: SCE, ORA, CLECA, TURN, SBUA, CFBF, AECA, FEA, California Manufacturers and Technology Association (CMTA), EPUC, EUF, CAL-SLA, and DACC. No party objected to the MC/RA settlement and it is therefore uncontested.

As noted in the decision in Pacific Gas and Electric Company's (PG&E's) most recent GRC Phase II (D.18-08-013), the Commission's preferred starting point for analyzing the reasonableness of a utility's revenue allocation is to assess whether it complies with the equal percent of marginal cost (EPMC) methodology. The EPMC methodology assesses the share of marginal costs imposed by each customer class on the utility, and then assigns the recovery of embedded and marginal costs to each class based on that share of marginal cost responsibility. For example, if the residential class is found to be responsible for

[5] D.18-08-013 at 13-15.

40% of a utility's marginal costs, then the residential class should be assigned 40% of the utility's total forecast costs. As described in D.18-08-013, the Commission's view is that EPMC is a transparent and fair way of allocating revenue responsibility among a utility's customer classes, assuming that marginal costs can be established.[6]

3.1. Marginal Cost Proposals

In this case, the parties to the MC/RA settlement did not agree on which marginal costs to use in allocating revenue among SCE's customer classes. Instead, they focused on the revenue allocation that they believed was reasonable given a range of marginal cost values, and then agreed to marginal cost values that would result in the desired revenue allocation outcome.[7] While artificial, these marginal cost values were apparently within the range of marginal cost values proposed by the parties in their prepared testimony, even though the settling parties declined to reveal the marginal cost values used by the MC/RA settlement. This is similar to the process used by the parties to PG&E's most recent GRC Phase II proceeding.[8]

This process of settling on artificial marginal cost values is somewhat opaque, and denies the Commission the ability to review the values and determine if they are reasonable in and of themselves. One of the witnesses at evidentiary hearings on the MC/RA settlement even suggested that the Commission should not attempt to divine true marginal cost values at this time

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[6] D.18-08-013 at 13-20.

[7] Transcript at 140-141, 144-145.

[8] D.18-08-013 at 25-26.

"until other [unnamed] issues are resolved at the Commission."[9] This creates certain inconsistencies with the scoping memo that requires the Commission to determine that SCE's marginal costs as determined in this proceeding are reasonable.

That said, the discussion in evidentiary hearings with parties to the MC/RA settlement revealed that the artificial marginal costs used in the settlement are considered to be reasonable by the parties. This appears to be the case due to the fact that the artificial marginal costs fall within the range of those originally proposed by the parties, and according to witnesses are values that survived rejection by the parties, rather than values that were acceptable in and of themselves.[10]

While this decision respects the wishes of the settling parties, and does not endorse a particular marginal cost as reasonable, it also finds that it is reasonable for the Commission to accept artificial marginal cost values for the purpose of revenue allocation and rate design, so long as those values are within the range of alternatives offered by the parties in their testimony. This allows the Commission to fulfill its obligation in the scoping memo to determine the reasonableness of SCE's marginal cost proposals. This also allows the Commission to continue to utilize the EPMC methodology for revenue allocation and rate design purposes.

3.2. Revenue Allocation Proposals

Once the parties' view of a reasonable revenue allocation was established, and artificial marginal costs within the range of party positions were created to

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[9] Transcript at 150.

[10] Transcript at 156-158.

establish that revenue allocation, the settling parties employed collars to regulate the change in average rates that resulted from the revenue allocation.[11] These collars restrict the changes in revenue allocation for a given class, reducing or raising a class's average rates when compared to the average rates they would have experienced had the collars not been imposed. This mechanism of ameliorating rate changes experienced by a utility's customer classes was endorsed in the recent PG&E GRC Phase II decision, despite the fact that it conflicts with EPMC revenue allocation principles.[12]

The table below illustrates the effect of collaring in the MC/RA settlement. The "uncollared" rate change column shows the change in average rates that would have occurred for SCE's bundled customer classes as a result of the MC/RA settlement's revenue allocation in the absence of collaring. The "collared" rate change column shows the change in average rates that will occur for SCE's bundled customers classes as a result of the collaring. In essence, collaring allowed the settling parties to moderate the impact of their preferred revenue allocation on the average rates for SCE's customer classes.

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[11] Transcript at 154-155 (SCE's witness referring to the principle of "gradualism" as justifying the capping and collaring of the revenue allocation).

[12] D.18-08-013 at 23-24.

SCE Bundled Rate Group	Uncollared Rate Change vs. January 2018 Rates	Collared Rate Change vs. January 2018 Rates
Residential	1.36%	- 1.72%
TOU-GS-1	- 9.47%	- 4.22%
TOU-GS-2	- 7.81%	- 4.21%
TOU-GS-3	- 6.23%	- 4.21%
TOU-8-Sec	- 5.07%	- 3.53%
TOU-8-Pri	- 4.04%	- 3.53%
TOU-8-Sub	- 4.11%	- 3.53%
TOU-PA-2	- 5.53%	- 4.22%
TOU-PA-3	0.56%	- 1.89%
Streetlights	8.61%	- 1.72%
System	**- 2.97%**	**- 2.97%**

As reflected in the table above, the MC/RA settlement ultimately proposes to adopt marginal costs and allocate revenue among SCE's customer classes such that all SCE customers[13] are forecasted to experience lower average rates. This is a result of a substantial decline in the estimated generation costs faced by SCE's bundled customers, driven by the retirement of certain ratepayer obligations related to the San Onofre Nuclear Generating Station (SONGS) and a decrease in the estimated cost of natural gas.[14]

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[13] Note that direct access customers and customers of Community Choice Aggregators (CCAs) in SCE's territory will not experience the same generation rate changes given that their generation rates are not subject to the terms of this settlement.

[14] Transcript at 135-137.

3.3. Functional Allocator Proposals

SCE proposed innovations to the methodology for calculating its generation and distribution marginal costs in this proceeding. They sought to distinguish marginal generation capacity costs between costs related to traditional peak generation capacity and costs related to the new concept of "flexible" generation capacity (flex capacity) that responds to steep ramps in required generation capacity.[15] Building from the interim "Peak Load Risk Factor" methodology adopted in SCE's 2016 Rate Design Window application,[16] SCE also sought to distinguish its marginal distribution costs in a similar fashion, splitting those costs between functions related to peak demands on the distribution grid and maintenance of the grid itself.[17]

Other parties agreed conceptually with SCE's approach to both sets of marginal costs.[18] The settling parties proposed a range of alternative approaches to calculating the relative split of marginal generation and distribution costs between these functions. As with the marginal costs themselves, the settling parties eventually agreed to adopt functional splits that were within the range of parties' proposals.

Through joint stipulation,[19] the settling parties agreed to provide the Commission with the settled functional allocators. For distribution marginal costs, the settling parties adopted a 50/50 split which assigned 50% of

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15 SCE-2 at 22-23.

16 D.18-07-006 at 22-24.

17 SCE-2 at 33, 39-43.

18 ORA-1, Chapter 3 at 4 and Chapter 1 at 2; SEIA-1 at 10-15, 17-19.

19 Stipulation of the Settling Parties Supplementing the Record in Support of Revenue Allocation Settlement Agreement (Joint Stipulation), filed August 3, 2018.

distribution marginal costs to peak demand requirements. This allows for material time differentiation of distribution rates. The Commission has previously found that such time differentiation of distribution rates is reasonable and desirable for the reasons described in D.18-08-013.[20] The complete list of functional allocators applied to specific distribution marginal costs appears below.

Distribution Marginal Cost Asset Category	**Grid Functional Allocator**	**Peak Functional Allocator**
Distribution – Substation	0%	100%
Distribution – Circuit	74%	26%
Subtransmission (Non-ISO) – Substation	0%	100%
Subtransmission (Non-ISO) – Circuit	80%	20%
Total	**50%**	**50%**

For generation marginal costs, the parties in their joint stipulation indicated that they settled on a functional split of marginal generation capacity of 60% peak capacity and 40% flex capacity. The 40% allocated to flex capacity uses a compromise methodology, which is comprised of 20% of the ramp allocation method proposed by SCE and 20% of the ramp allocation method proposed by EPUC.[21]

The MC/RA settlement establishes a process going forward where SCE will create a working group to explore how to incorporate a flexible generation capacity component into the revenue allocation process. Ultimately, SCE

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[20] D.18-08-013 at 47-51, CoL 33, CoL 56, CoL 57, CoL 59.

[21] Joint Stipulation at 5.

commits to performing one or more studies that will explore the split of marginal generation capacity costs between peak and flex/ramp functions. The study or studies generated by this process may be used by SCE in its next GRC Phase II to refine its marginal generation capacity cost proposal.[22] With respect to marginal distribution capacity costs, the amended motion supporting the MC/RA settlement states that SCE will share more granular data with ORA on the nature of its distribution costs, including nameplate capacity and load data at the regional and substation level, and to produce a load-weighted average distribution marginal cost at each level of the system.[23]

This decision finds that these next steps as contemplated by the MC/RA settlement are reasonable and should be pursued. However, the development of functional splits of SCE's marginal generation costs and distribution costs may have implications in other Commission proceedings. These functional splits could easily be applied to the other major electric utilities in their GRC Phase II proceedings, but as of now there are no discrete proposals to do so. Other Commission proceedings may also make use of this distinction in marginal costs.

So that the Commission may thoughtfully consider the impact of SCE's proposals on other utilities and proceedings, this decision requires the working group process set out by the MC/RA settlement to include PG&E and the San Diego Gas & Electric Company (SDG&E) as participants so that they may observe the process and have the opportunity to propose similar methodologies in their upcoming GRC Phase II proceedings, if they so choose. Furthermore, the Commission encourages SCE to reach out to various teams in the Commission's

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[22] MC/RA settlement at 22.

[23] Amended Motion to Adopt the MC/RA settlement at 12.

Energy Division that engage in proceedings beyond rate design, such as the Integrated Resources Planning (IRP) proceeding (Rulemaking (R.) 16-02-007), so that they may gain experience with this methodology and its development.

3.4. Findings Regarding the MC/RA Settlement

The Commission's standard of review for uncontested settlements appears in Section 2 above. The Commission must review the MC/RA settlement to determine if it is reasonable in light of the whole record, consistent with law, and in the public interest. The Commission reviewed the MC/RA settlement's terms, and an Administrative Law Judge (ALJ) assigned to this proceeding examined witnesses testifying on behalf of the settling parties during evidentiary hearings on July 17, 2018. This decision finds that the MC/RA settlement should be approved for reasons including the following:

- The MC/RA settlement is not contrary to any law or previous Commission decision.
- The marginal costs used by the MC/RA settlement, while not subject to full Commission review, are apparently within the range of values proposed by the parties, and are therefore reasonable in light of the whole record.
- Parties representing all customer groups presented testimony on revenue allocation issues and participated in settlement negotiations.
- Parties worked diligently and focused on multiple simulations of marginal cost and revenue allocation impacts, and ultimately agreed to focus on the reasonableness of the settlement's revenue allocation rather than marginal cost responsibility.
- The settlement's revenue allocation is a balanced outcome that leads to reductions in average rates for ratepayers and is therefore in the public interest.

SCE must implement the terms of the MC/RA settlement as soon as practicable after the issuance of this decision.

4. Economic Development Rate Design

A settlement amongst the parties on economic development rate design issues (EDR settlement) was filed on May 30, 2018. The settling parties are SCE, ORA, TURN, and SBUA. EUF and CCEA participated in initial settlement discussions and are aware of the general terms of the EDR settlement but did not join or oppose it. The EDR settlement is therefore uncontested.

4.1. SCE's Existing EDR Program

Currently, commercial customers with loads exceeding 200 kilowatts (kW) may apply to participate in the EDR program and receive a five-year discount of 12% on their monthly bill.[24] Some EDR applicants must verify through an affidavit that but for the EDR program, alone or in combination with other incentives, they would either shutter their operations or move their operations outside of California.[25] SCE also engages in the following process when reviewing an EDR application:

- An SCE economic development consultant contacts customers who have expressed an interest in the EDR program.
- Customers respond by submitting a letter of interest explaining their need.
- SCE conducts a rate analysis to determine initial eligibility (*e.g.,* confirmation that monthly load is at least 200 kW and that the customer is not a government entity or a residential customer).

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[24] SCE-4 at 91.

[25] SCE-4 at 100.

- Customers provide information to SCE including total number of jobs and associated benefits/salary as well as a five-year determination of operating costs comparing their California location and their potential out-of-state location.
- SCE reviews the information submitted by the customer and approves or denies the customer's request.
- SCE conducts an energy audit based on projected usage to determine energy growth projections over the term of the EDR contract.
- Once approved, SCE enters into an EDR contract with the customer which documents, among other things, the expected commencement date and expected energy load requirements.[26]

In hearings SCE stated that, despite this process, they rejected only two EDR applications since 1996.[27]

An "enhanced" EDR is available to customers that would otherwise qualify for the standard EDR and are located in California cities or counties with unemployment rates that are 125% or more of the previous year's statewide average unemployment rate. Enhanced EDR participants receive a 30% discount on their monthly bill. In D.15-04-006, the Commission approved a settlement between ORA and SCE that capped participation in SCE's EDR program to 200 MW, of which enhanced EDR participation was capped at 40 MW.[28]

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[26] SCE-4 at 99.

[27] Transcript at 210. While there is a requirement for SCE's EDR applicants to have their applications reviewed by the Governor's Office of Business and Economic Development (Go-BIZ), SCE reports that no EDR applications have ever been rejected by Go-BIZ. This decision does not detail their review process here.

[28] SCE-4 at 91.

No law prohibits SCE's EDR program. Public Utilities Code Section 740.4(a) requires the Commission to authorize utility programs that encourage economic development, and Public Utilities Code Section 740.4(h) refers to the costs of "rate discounts supporting economic development programs" as eligible for rate recovery, so long as the ratepayers of the utility derive a benefit from the program. According to SCE, their EDR program attracted and/or retained 136,454 kW of load, 539 gigawatt hours (GWh) of usage, and 7,004 jobs in 2016. SCE also claims that their EDR customers will make a "contribution to margin" that ensures that such customers pay their fair share of SCE's marginal costs.[29] The 200 MW program cap is fully subscribed as of December 31, 2016.[30]

4.2. Proposed Changes to SCE's EDR Program

The EDR settlement proposes to modify SCE's EDR program by eliminating the enhanced EDR option and setting a standard discount for all EDR participants at 12%. The current eligibility requirements and review processes would remain with the following exceptions: 1) the need to demonstrate that a business is located in an area with relatively high unemployment is obviated by the elimination of the enhanced EDR option; and 2) the "but for" affidavit requirement is extended to all EDR applicants. In

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[29] SCE-4 at 96 ("the expected revenues from EDR participants should account for the sum of distribution and generation marginal costs and [non-bypassable charges] in each year of the [EDR] contract's five-year term").

[30] SCE-4 at 91.

addition, annual EDR reports must be filed with ORA's Electricity Pricing and Customer Programs (EPCP) branch.[31]

Other proposed modifications to the EDR program are intended to make it available to small business customers. These proposed changes would: 1) lower the minimum kW threshold for applicants from 200 kW to 150 kW; 2) permit account aggregation to meet the new threshold only to the extent the accounts are located at the same physical facility; and 3) offer the opportunity for 20 small business accounts (defined as having maximum loads below 150 kW) to take service on the EDR tariff.[32]

All of these modifications reflect proposals made by settling parties in their testimony or reflect compromises among the positions taken by parties.

Other elements of the existing EDR program would remain the same, such as the overall 200 MW cap on participation and the prohibition on participation by residential or governmental customers.[33] During hearings, SCE granted that the EDR program would naturally terminate if no new EDR program was authorized by the Commission in the future.[34]

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[31] EDR settlement at 5-6.

[32] Motion to adopt EDR settlement at 5.

[33] EDR settlement at A-5.

[34] Transcript at 119-124.

4.3. Findings Regarding the EDR Settlement

The Commission's standard of review for uncontested settlements appears in Section 2 above. The Commission must review the EDR settlement to determine if it is reasonable in light of the whole record, consistent with law, and in the public interest. The Commission reviewed the EDR settlement's terms, and an ALJ assigned to this proceeding examined witnesses testifying on behalf of the settling parties at evidentiary hearings on July 17, 2018. This decision finds that the EDR settlement should be approved for reasons including the following:

- The modifications to the EDR program are reasonable in light of the whole record as they represent a compromise among the EDR positions established by settling parties in their prepared testimony.

- The expansion of the affidavit requirement to all of SCE's EDR applicants will enhance the safeguards that aim to prevent cost-shifting, and is therefore in the public interest.

- Setting the EDR discount at a standard rate of 12% will ensure that EDR customers cover their marginal costs and responsibilities for non-bypassable charges.

- The EDR settlement's terms are consistent with the law and in the public interest as the historic attraction and retention of thousands of jobs in SCE's territory by EDR customers confers sufficient ratepayer benefits to justify the continuation of SCE's EDR program per Public Utilities Code Section 740.4(h).

- The EDR settlement is in the public interest as the agreement is a reasonable compromise between stakeholders representing a broad range of interests.

SCE must implement the terms of the EDR settlement as soon as practicable after the issuance of this decision.

5. Streetlight, Area Light, and Traffic Control Rate Design

A settlement amongst the parties on streetlight, area light, and traffic control rate design issues (streetlight rate design settlement) was filed on July 6, 2018. The settling parties are SCE, CAL-SLA, and CASL. These are the only parties that filed testimony on streetlight rate design issues. The streetlight rate design settlement is therefore uncontested.

CASL's filed a motion to withdraw the March 23, 2018 direct testimony of Fred Lyn on behalf of the Coalition for Affordable Streetlights, and Chapter IV of the direct testimony of William A. Monsen on behalf of the Coalition for Affordable Streetlights. The motion is granted, and the streetlight rate design settlement does not address the issues raised in these portions of CASL's testimony.

5.1. Non-allocated Revenues

The issue of non-allocated streetlight revenue concerns SCE's recovery of costs for SCE-owned streetlight facilities, such as lamps and poles. SCE's testimony states that "[f]or non-metered lamp types, the non-allocated revenue requirement is based on an accounting of the net plant-in-service, inclusive of operation and maintenance (O&M) and tax treatments, associated with non-metered street light facilities."[35] SCE and the other settling parties had differing methodological approaches for determining the non-allocated revenues and the rate at which they should be applied to various streetlight rate schedules.

The settling parties reached a three-part compromise. First, the settling parties agreed to set non-allocated revenues at an initial level of $76,466,000 as

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[35] SCE-4 at 71.

reflected in the MC/RA settlement, and then adjust this amount in future years per the terms of the streetlight rate design settlement. Second, facilities charges would be allowed to increase 5% to cover the non-allocated revenue requirement, with any residual amount recovered through distribution energy charges. Third, non-allocated revenues would be updated annually but the facilities charge would remain fixed at the level established upon initial implementation of the streetlight rate design settlement.

5.2. Energy Charges and Customer Charges

The settling parties agreed that SCE will set the energy charges for streetlight rate group residually after non-energy charges (including non-allocated revenue) are computed. With respect to customer charges, SCE and CAL-SLA disagreed on the methodology used to compute customer charges for AL-2 and LS-3 customers. The settling parties eventually agreed to set customer charges for AL-2 and LS-3 customers by splitting the difference between the methodologies proposed by SCE and CAL-SLA.[36]

SCE proposed, and parties did not object, to collect a maximum of 27% of allocated revenue for TC-1 (traffic control) customers through a customer charge. SCE later clarified that this precise figure of 27% is based on a settled position adopted by the parties in SCE's 2012 and 2015 GRC Phase II. The settling parties in both the 2012 and 2015 GRC Phase II proceedings apparently adopted that percentage after weighing various fixed and variable revenue recovery numbers. SCE reported that in both cases, the TC-1 rate design began as a marginal cost-based rate that was then adjusted to mitigate bill impacts for some customers

36 Motion to adopt streetlight rate design settlement at 6.

within the group. Parties agreed to use the allocation of cost recovery between fixed and volumetric charges as the mechanism to mitigate these impacts.

Interestingly, the 27% figure does not accurately reflect the marginal customer cost for TC-1 customers, which SCE calculates to be $19/month. The customer cost at 27% ends up being $13.93/month. SCE grants that the 27% figure is not based on a scaled marginal cost but based on a settled position adopted by the parties in both the 2012 and 2015 GRC Phase II streetlight and traffic control settlement agreements.[37] Thus, the figure of 27% appears to be retained for the sake of historic practice, rather than for its relationship to the marginal TC-1 customer cost.

5.3. Rate Option for Distribution Pole-Mounted Streetlights

Pursuant to the streetlight rate design settlement adopted in SCE's previous GRC Phase II proceeding, SCE proposed a rate option in this proceeding for lamps that are mounted on SCE's distribution poles (*e.g.,* those poles that serve other needs other than supporting streetlights, such as electric distribution and falcon roosting). CAL-SLA disputed certain elements of SCE's proposal with respect to an inventory fee for non-transfer entities (*i.e.,* those cities that did not purchase streetlight facilities from SCE when given the opportunity). Settling parties agreed that SCE will provide a credit on a per lamp basis for customers that take service on the rate and assess an inventory fee for non-transfer entities that take service on the rate. SCE also agreed in the settlement to provide additional customer outreach to eligible streetlight customers to make them aware of this new option.

[37] Transcript at 208-210.

5.4. Dimmable Streetlight and Ancillary Device Rate Design

While SCE did not propose a dimmable streetlight or ancillary device rate option in their testimony, CAL-SLA proposed such options in their testimony. CASL expressed support for the development of a rate structure for dimmable lamps and ancillary devices.

The settling parties agreed that SCE will conduct an evaluation of the feasibility of a dimmable streetlight rate option and an ancillary device rate option. SCE's feasibility assessment will include a determination of equipment and infrastructure needs, and impacts to SCE's billing system that would be required to accommodate these new rates. Per the terms of the settlement agreement, SCE may propose these new rate options in its next GRC Phase II application depending on the results of the feasibility assessment, the approval of any necessary funding requirements in its next GRC Phase I proceeding, and/or the deployment schedule for any necessary equipment.

5.5. Findings Regarding the Streetlight Rate Design Settlement

The Commission's standard of review for uncontested settlements appears in Section 2 above. The Commission must review the streetlight rate design settlement to determine if it is reasonable in light of the whole record, consistent with law, and in the public interest. The Commission reviewed the streetlight rate design settlement's terms, and an ALJ assigned to this proceeding examined witnesses testifying on behalf of the settling parties in evidentiary hearings on July 18, 2018. This decision finds that the streetlight rate design settlement should be approved for reasons including the following:

- The illustrative rates for streetlight rate group customers that result from the settlement reflect modest increases and decreases to most rate components, making the rate changes reasonable and in the public interest.

- Customer charges for AL-2 and LS-3 customers in particular see significant reductions as a result of the settlement.
- The parties bargained in good faith and sought compromises among their litigated positions.
- The provisions of the streetlight rate design settlement are not contrary to law.
- SCE's implementation of a pole-mounted rate option for certain streetlight rate group customers, and outreach to eligible customers, is in the public interest as it expands rate options for certain customers.

SCE must implement the terms of the streetlight rate design settlement as soon as practicable after the issuance of this decision.

5.6. Mandated Future Proposal for a Dimmable Streetlight Rate Option

As in the recent decision in PG&E's recent GRC Phase II,[38] and based on the testimony of CAL-SLA in this proceeding,[39] this decision finds that a dimmable streetlight system for streetlight customers is in the public interest and should be pursued expeditiously. The testimony of CAL-SLA also reveals that municipalities within SCE's service territory are actively working toward making their streetlights dimmable. The testimony states that:

> Across SCE's service area, public agencies are evaluating network controlled, dimmable street lights and ancillary devices attached to customer-owned (LS-2) street light poles.

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[38] D.18-08-013, CoL 65.

[39] CALSLA-1 at 18-19 (setting out the benefits of a dimmable streetlight system such as increased conservation, reduced greenhouse gas emissions, and public safety applications).

> A standard, or static, street light is made up of a street light pole, mast arm, luminaire, wiring, and a photo sensor that turns the lamp on and off at dusk and dawn. Dimmable street lights have a module in place of the photo sensor that allows the customer to directly control the light output. On behalf of 11 member cities, the Western Riverside Council of Governments (WRCOG) is reviewing technologies in hopes of initiating a dimmable pilot program…. [T]he City of Rancho Cucamonga has installed 1,000 dimmable controls. New rate structures are needed to accommodate these technologies that are already being deployed in SCE territory.[40]

This decision agrees with CAL-SLA on the need for a dimmable streetlight program and finds that because of the public interest in developing such programs and to facilitate the efforts made by municipalities in this regard, SCE must propose a dimmable streetlight rate option in its next GRC Phase II application for Commission consideration. This is not a modification of the streetlight rate design settlement per se.[41] SCE may make a parallel argument in its application that the dimmable streetlight rate option should not be pursued, affording SCE the discretion the settlement allows it; but the Commission must be afforded the opportunity to review a formal SCE proposal for such a rate option as well.

SCE does not have first-hand experience with dimmable streetlight programs, unlike PG&E and SDG&E.[42] This means that SCE should become familiar with dimmable streetlight programs before they file a proposal for a

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[40] CALSLA-1 at 18.

[41] The streetlight rate design settlement at 13 states that "[a]t its election and in its discretion, SCE may propose a [dimmable streetlight rate option]…".

[42] CALSLA-1 at 20.

dimmable streetlight rate option in their next GRC Phase II proceeding, including by learning from SDG&E's and PG&E's experiences with dimmable streetlight pilot programs.

6. Settlement on Legacy TOU Rates for Solar Customers

On July 23, 2018, SCE served a motion to adopt a settlement agreement on TOU period mitigation for solar grandfathered commercial and industrial customers (TOU settlement).[43] This agreement does not apply to potential legacy solar customers in the agricultural and pumping class. The parties to the TOU settlement are SCE, SBUA, EUF, CLECA, SEIA, and CALSSA. These include all of the parties that served testimony on this issue, and therefore the TOU settlement is uncontested.

[43] This decision is reluctant to use the term "grandfathering" in this decision to describe the rates and TOU periods applicable to legacy solar customers given the etymology of the term. Therefore, this decision will refer to this settlement as the "TOU settlement." Those customers that are eligible for "grandfathering" under D.17-01-006 are generally referred to as "legacy" solar customers in this decision.

6.1. Content of TOU Settlement

The TOU settlement seeks to apply the requirements of D.17-01-006, which set out guidelines for how to apply changes in TOU peak periods to utility customers with existing customer-sited renewable generation systems. These customers with existing systems were to be given the opportunity to remain on "legacy" TOU periods when new TOU peak periods were applied to other customers. The decision deferred consideration of the actual rate design to be used for legacy TOU customers. D.17-01-006 held that other changes in rate design, including allocating marginal costs to TOU periods and setting specific rate levels, were to be litigated in utility-specific rate proceedings, such as the instant proceeding.[44]

The TOU settlement in this proceeding addresses the eligibility for legacy TOU rates, the duration of the legacy TOU rates, the available rate options for legacy TOU customers, the rate design process for legacy TOU rates, and other potential mitigation measures.

SCE generally proposed in its testimony to limit legacy TOU rate eligibility and duration to those customers and time periods as defined in D.17-01-006 and D.17-10-018. The settling parties agreed to SCE's proposal.

SCE proposed a variety of legacy TOU rate options for its customers, which were either accepted or unopposed by the settling parties in their testimony. Notably, the settlement creates potential rate options for RES-BCT customers[45] but reserves determination of legacy TOU rates specifically for

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

[45] Motion to adopt TOU settlement at 4.

RES-BCT generating accounts to a separate track of this proceeding (discussed further in Section 9).[46]

In their testimony, SCE and SEIA proposed differing rate design processes for the various legacy TOU rates. The TOU settlement adopts a compromise position where SCE's approach is generally favored, but certain of SEIA's recommendations for changes to the proposed GF-R rate are adopted.

The settling parties generally agreed to SCE's proposal to adjust the legacy TOU rates periodically on a System Average Percent Change (SAPC) basis, consistent with all other rates. The settling parties agreed that the structure of the legacy TOU rates may be further revised in SCE's 2021 GRC Phase II proceeding.

While SEIA served testimony in support of an optional fixed indifference payment in lieu of legacy TOU rate participation, the settling parties did not agree to this proposal and instead accept the agreed-upon legacy TOU rates as the sole mitigation measure for legacy TOU customers in the commercial and industrial rate classes.

6.2. Findings Regarding the TOU Settlement

The Commission's standard of review for uncontested settlements appears in Section 2 above. The Commission must review the TOU settlement to determine if it is reasonable in light of the whole record, consistent with law, and in the public interest. The Commission reviewed the TOU settlement's terms, and this decision finds that the TOU settlement should be approved for reasons including the following:

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[46] Motion to adopt TOU settlement at 5, fn 3.

- The TOU settlement is in the public interest as it is a reasonable compromise of positions taken by parties that represent the interests of a wide variety of customers that are affected by the terms of the TOU settlement.
- The TOU settlement creates some measure of rate certainty for legacy solar customers, while limiting the cost shifts imposed on other non-legacy solar customers.
- The TOU settlement complies with the terms of D.17-7. 01-006 and D.17-10-018 and is therefore consistent with the law on this issue.
- The TOU settlement is reasonable in light of the whole record as it largely adopts positions taken by parties in their testimony or adopts compromises of those positions.

SCE must implement the terms of the TOU settlement as soon as practicable after the issuance of this decision.

7. Medium and Large Power Rate Design Settlement

On August 3, 2018, SCE served a motion to adopt a settlement agreement on rate design for the medium and large power rate group (MLP settlement). The parties to the MLP settlement are SCE, CLECA, EUF, SEIA, CMTA, CALSSA, FEA, EPUC, and DACC. These include all of the parties that served testimony on this issue, and therefore the MLP settlement is uncontested.

7.1. Content of the MLP Settlement

The MLP settlement resolves issues related to rate design for what is known as the "medium and large power rate group." These customers generally have peak loads between 20kW and 500kW (rate groups TOU-GS-2 and TOU-GS-3) and above 500kW (rate group TOU-8). The major rate design issues addressed by the MLP settlement include:

- The replacement of Option B with new Option D as the new base rate design for TOU-GS-2 and TOU-GS-3 (*i.e.,* "medium power") customers) and TOU-8 (i.e., "large power") customers.

- The appropriate design of the new Option D rates.
- The replacement of Options A and R with new Option E as the optional rate design for TOU-GS-2, TOU-GS-3, and TOU-8 customers.
- The appropriate design of the new Option E rates.
- Eligibility requirements for Option E customers in the TOU-8 rate classes.
- Real-Time Pricing, Standby, and Reliability Back-Up Service rates.

7.1.1. Time-differentiation of Distribution Revenue Collection

The MLP settlement adopts movement towards time-differentiation of distribution costs. Both Options D and E for MLP customers shift distribution cost recovery away from non-coincident facilities-related demand (FRD) charges, and towards time-related demand (TRD) charges and volumetric energy charges. This comports with the recent decision in the PG&E GRC Phase II proceeding (D.18-08-013) where the Commission held that:

- Heavy reliance on non-coincident demand charges is generally disfavored by our historic rate design principles because non-coincident demand charges do not reflect cost causation for primary distribution, transmission, or generation capacity costs (Conclusion of Law 56).
- Rate designs that heavily rely on non-coincident demand charges also promote inefficient use of energy contrary to state policy goals encouraging economically efficient and socially beneficial energy usage (Conclusion of Law 57).

The MLP settlement complies with these holdings by generally moving distribution revenue collection to charges that are time-variant. The tables below illustrate that changes adopted by the MLP settlement to relative amounts of distribution revenue collected by certain rate schedules through time-variant charges.

	Percentage of Distribution Revenue Collected Through		
	Volumetric Energy Charges	Time-Related Demand Charges	Non-coincident Demand Charges
Current TOU-GS-2, Option B Schedule	0%	0%	100%
Proposed TOU -GS-2, Option D Schedule	12%	35%	53%
Current TOU-GS-2, Option R Schedule	33%	0%	67%
Proposed TOU-GS-2, Option E Schedule	70%	0%	30%
Current TOU-GS-3, Option B Schedule	0%	0%	100%
Proposed TOU-GS-3, Option D Schedule	12%	33%	55%
Current TOU-GS-3, Option R Schedule	50%	0%	50%
Proposed TOU-GS-3, Option E Schedule	70%	0%	30%
Current TOU-8-SEC, Option B Schedule	0%	0%	100%
Proposed TOU-8-SEC, Option D Schedule	12%	33%	55%
Current TOU-8-SEC, Option R Schedule	17%	0%	83%
Proposed TOU-8-SEC, Option E Schedule	70%	0%	30%
Current TOU-8-PRI, Option B Schedule	0%	0%	100%
Proposed TOU-8-PRI, Option D Schedule	12%	32%	56%
Current TOU-8-PRI, Option R Schedule	28%	0%	72%
Proposed TOU-8-PRI, Option E Schedule	70%	0%	30%
Current TOU-8-SUB, Option B Schedule	0%	0%	100%
Proposed TOU-8-SUB, Option D Schedule	0%	46%	54%
Current TOU-8-SUB, Option R Schedule	48%	0%	52%
Proposed TOU-8-SUB, Option E Schedule	78%	0%	22%

7.1.2. Impacts of the MLP Settlement on Electric Vehicle Rates

While the MLP settlement revises some of the existing electric vehicle (EV) rates for SCE's MLP customers, these rates are due to be replaced through a process already completed in the Transportation Electrification proceeding (A.17-01-020, et al). The MLP settlement also touches on EV rates in the sense that the Option E rates are available to MLP customers that conduct some form of zero emission vehicle (ZEV) charging on site.

In both of these respects, this decision finds that the settlement's treatment of EV rates is reasonable given that the primary EV rates for MLP customers are governed by the Transportation Electrification proceeding and not by this GRC Phase II proceeding. SCE must file an information-only advice letter if the total customer load served by Option E customers that qualify for Option E due to their charging of ZEVs exceeds the total customer load on rates TOU-EV-8 and TOU-EV-9. This will ensure that the Commission is aware of MLP customer preference for Option E rates compared to EV rates.

7.1.3. Providing a Menu of Rates for MLP Customers

Also in accord with the recent decisions in other electric utility GRC Phase II proceedings is the MLP settlement's creation of highly differentiated rate options for MLP customers to choose from. In particular, TOU-GS-2 and TOU-GS-3 customers will be able to choose from two options – Options D and E – without limitation.

The MLP settlement proposes that the base rate for MLP customers be the Option D variant of TOU-GS-2, TOU-GS-3, and TOU-8. Option D relies on substantial peak-period demand charges for revenue collection, and also contains highly-differentiated energy charges to further incent customer behavior that benefits the grid and avoids marginal utility investments. The MLP settlement also creates an optional rate – Option E – that may benefit certain customer groups that would not otherwise respond well to the peak demand charge-heavy rate design of Option D. The Option E rate does not eliminate non-coincident demand charges, but it reduces them to make the rates more aligned with time-dependent cost-causation, which helps to provide more actionable price signals to customers considering a purchase of distributed energy resource (DER) technology. This also helps to achieve some of the goals of the Commission's DER action plan.

Option E is available without limitation to the TOU-GS-2 and TOU-GS-3 customer groups. For TOU-8, Option E is limited to 250 MW of customer-sited energy resources. Parties to the MLP settlement suggested at hearings that this cap may not be reached before the next SCE GRC Phase II proceeding, but there is uncertainty on that point.[47] Option E is available to TOU-8 customers if they meet the following eligibility requirements:

- Meet the eligibility requirements for current Option A, being:
    - customers who participate in permanent load shifting (PLS) where eligible systems account for at least 15% of the customer's annual peak demand, as recorded over the previous 12 months,
    - "cold ironing" pollution mitigation programs, or
    - the charging of eligible ZEVs intended for the transport of people or goods.
- Meet the eligibility requirements of current Option R (*i.e.* customers with annual peak demands not

[47] Transcript at 258-259.

exceeding four MW who install, own or operate solar, wind, fuel cells or other eligible onsite Renewable Distributed Generation Technologies as defined by the California Solar Initiative or the Self-Generation Incentive Program (SGIP)).

  - Option R eligible systems must have a net renewable generating capacity equal to or greater than 15% of the customer's annual peak demand, as recorded over the previous 12 months.[48]

- Customers with energy storage systems installed on site, where the system must have a minimum discharge capacity equal to or greater than 20% of the customer's annual peak demand, as recorded over the previous 12 months.
- All Option E customers must have annual peak demands not exceeding five MWs.[49]
- While a 250 MW participation cap is imposed for customers with DER technologies, the capacity of new customers who are utilizing technologies that would have made them eligible for Option A (see first bullet) do not count against this cap.

The MLP settlement also requires SCE to report regularly to the Commission's Energy Division regarding the progress toward the 250 MW cap, so that the Commission and parties may be aware of any impending closure of

[48] At hearings, parties testifying on behalf of the MLP settlement clarified that a customer would only be eligible for Option E if the SGIP-eligible technology they possessed on site was renewably powered (Transcript at 252). This requirement is not intended by the parties to the MLP settlement to exclude stand-alone energy storage (SCE comments at 3, fn 4). The Commission's approval of the MLP is conditioned on this clarification to the MLP settlement.

[49] SCE's comments to the proposed decision indicate that the peak demand limitation for eligible Option E customers will be five MW, as opposed to the current Option R peak demand limitation of four MW.

the Option E rate to TOU-8 customers in advance of SCE's next GRC Phase II proceeding.

In order to provide a true menu of rate options, and therefore comply with previous Commission decisions, it is necessary that MLP customers be made aware of Option E and understand the benefits it may provide them. This decision orders SCE to provide Energy Division with an information-only Tier 1 advice letter enclosing SCE's marketing material for the Option E rates for MLP customers, the total customer enrollments in Option E in each of the TOU-GS-2, TOU-GS-3, and TOU-8 tariffs, the bill impacts for customers that switch to Option E, and the rate impact on non-Option E customers due to customer enrollment on Option E in each of the TOU-GS-2, TOU-GS-3, and TOU-8 tariffs. This Tier 1 advice letter shall be filed annually by the end of 2019, 2020, 2021, and 2022.

7.2. Findings Regarding the MLP Settlement

The Commission's standard of review for uncontested settlements appears in Section 2 above. The Commission must review the MLP settlement to determine if it is reasonable in light of the whole record, consistent with law, and in the public interest. The Commission reviewed the MLP settlement's terms, and an ALJ assigned to this proceeding questioned witnesses testifying on behalf of the MLP settlement in evidentiary hearings on August 9, 2018. This decision finds that the MLP settlement should be approved for reasons including the following:

- The MLP settlement shifts a large portion of distribution cost recovery to time-dependent demand and energy charges, in accord with the Commission's rate design principles and recent decisions in other electric utility GRC Phase II proceedings (D.17-08-030 and D.18-08-013).

- The MLP settlement creates rate options for MLP customers that are in accord with the direction in D.17-01-006.
- As it complies with D.17-01-006, D.17-08-030, and D.18-08-013, the MLP settlement complies with the law and is in the public interest.
- As the MLP settlement is uncontested and is agreed to by all the parties that submitted testimony on MLP rate design issues, and because certain elements of the MLP settlement represent the product of arms-length negotiation and compromise between those parties, the MLP settlement is reasonable in light of the whole record.

SCE must implement the terms of the MLP settlement as soon as practicable after the issuance of this decision.

8. Residential and Small Commercial Rate Design Settlement

On July 30, 2018 SCE filed and served a motion to adopt a settlement agreement on residential and small commercial rate design (RSC settlement). The parties to the RSC settlement are SCE, ORA, TURN, SEIA, CALSSA, NRDC (residential rate design only), SBUA (small commercial rate design only), and WMA (residential rate design only). EUF served testimony on small commercial rate design issues but does not support or oppose the RSC settlement. The RSC settlement is therefore uncontested.

This decision bifurcates its discussion of residential and small commercial rate design issues.

8.1. Residential Rate Design Issues

The consideration of residential rate design issues in this proceeding is a complex affair owing to the multiple proceedings impacting SCE's residential rate designs during the duration of this GRC Phase II proceeding. SCE included in its direct testimony a summary of SCE's rate design-related proposals that were then pending in two other applications: A.16-09-003 (SCE's 2016 Rate Design Window Application) and A.17-04-015 (SCE's Default Residential TOU Application).

A.16-09-003 was disposed of by D.18-07-006, which adopted SCE's new proposed TOU periods for its non-residential customers. A.17-04-015 was dismissed by the Commission in D.17-08-024, and SCE refiled its default residential TOU application in December 2017. That application is pending consideration as part of the consolidated A.17-12-011 proceeding.

Most of SCE's non-fixed charge residential rate design proposals will be addressed in Phase II-B of A.17-12-011. The proposed default TOU periods for SCE's residential customers in that proceeding are generally consistent with those approved for SCE's non-residential customers in D.18-07-006.

The motion to adopt the RSC settlement states that no proposal in SCE's portion of the A.17-12-011 proceeding addresses optional residential rates,[50] the baseline allowance, or the level of low-income discounts.[51] The residential rate design settlement in this proceeding therefore focuses on those core issues, as well as others not addressed in other proceedings.

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50 SCE's proposal in A.17-12-011 actually includes two different default rates, either of which may be used by an SCE customer. One could argue that this means that optional rates are under consideration for SCE residential customers in A.17-12-011.

51 Motion to adopt RSC settlement at 4.

8.1.1. Baseline Allowance for Residential Customers

The RSC settlement proposes to increase the baseline allowance for basic residential customers (*i.e.,* non-all electric customers) from the current level of 53% of average usage in each climate zone to the statutory maximum of 60%. The average usage is determined by examining basic and all-electric usage by climate zone for the years 2010-2016.[52]

8.1.2. Closing Outdated Optional TOU Rates and Provisions for Legacy Solar Customers

Subsequent to D.18-07-006, many of SCE's optional residential TOU rates now employ outdated peak periods that do not align with the costs faced by SCE. The RSC settlement proposes to close to new customers and eventually eliminate several now-obsolete optional residential TOU rates. However, existing solar customers are entitled by D.16-01-044 and D.17-01-006 to remain on outdated TOU rates for a certain period of time (i.e., the legacy period). A table describing these changes appears below.

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[52] RSC settlement at 10.

Optional Residential Rate	Peak Period	Closed to New Customers[53]	Existing Customer Transfer Date	Provisions for Legacy Solar Customers
TOU-D-T	12-6 p.m.	Implementation of decision in A.17-06-030	Q4 2020[54]	May stay on rate for duration of their legacy period
TOU-D-A	2-8 p.m.	Implementation of decision in A.17-06-030	Q4 2020	May stay on rate for duration of their legacy period
TOU-D-B	2-8 p.m.	Implementation of decision in A.17-06-030	Q4 2020	May stay on rate for duration of their legacy period
TOU-EV-1[55]	12-9 p.m.	Implementation of decision in A.17-06-030	July 31, 2022	May stay on rate for duration of their legacy period

Some minor structural changes to these rates are proposed by the RSC settlement. For example, time-differentiation of distribution charges will be introduced to the rates, and TOU-D-A will see some shifting of revenue components while the distribution rates will be set at the marginal cost floor for the winter super off-peak period.[56] However, the TOU periods for these outdated rates will remain constant so long as a customer is eligible to remain on the rate.

[53] While it is not clear from the settlement when the "implementation" of this decision by SCE will actually be, this decision assumes that the rates will be closed to new customers no later than March 1, 2019.

[54] Estimated date based on estimated completion of SCE's Customer Service Re-Platform (CSRP) project, which is the new billing and customer care system that SCE is proposing to use to replace its existing billing system. If the CSRP work is completed before Q4 2020, then the RSC settlement may be read to allow for an earlier transition date for existing customers.

[55] This rate requires residential customers to have a separate meter for their EV load.

[56] RSC settlement at 12.

8.1.3. Creation of a New Optional TOU Rate for Residential Customers

While A.17-12-011 considers default TOU rates for SCE's residential customers, this proceeding considers other optional TOU rates for SCE's residential customers. The RSC settlement proposes to create such an optional rate, to be known as TOU-D-PRIME. This optional rate is designed to be beneficial for higher-usage customers that employ technologies such as EVs, storage, or heat pump systems. This rate would use TOU periods recently authorized by the Commission in D.18-07-006: a 4-9 p.m. peak period, and a super off-peak period during the winter season from 8:00 a.m. – 4:00 p.m.[57] As proposed, the rate includes a $12/month fixed charge. Because the rate provides significant rate differentials for higher-usage customers, the RSC settlement adopts procedures to address potential revenue shortfall that might arise from the rate. These include convening a meet and confer process if revenue differentials of $50 million annually are reached and limiting eligibility to those customers with qualifying technologies such as EVs.[58] The rate will be available to customers concurrent with the implementation of this decision.[59]

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[57] SCE-4 at 37. The RSC settlement notes that the rate charged during super off-peak and off-peak winter periods for TOU-D-PRIME will actually be identical to simplify the rate and hopefully increase customer understanding.

[58] Motion to adopt RSC settlement at 10. Existing TOU-D-A and TOU-D-B customers are also eligible to enroll when they are transferred off those rates as expected in Q4 2020. The RSC settlement also states that new customers may also enroll in TOU-D-PRIME without any eligibility restrictions for the first two months after implementation of the decision in this proceeding (i.e., March – May, 2019).

[59] RSC settlement at 15. While it is not clear from the settlement when the "implementation" of this decision by SCE will actually be, this decision assumes that the rate will be available no later than March 1, 2019.

8.1.4. Master Meter Discount

The RSC settlement updates the submetering discounts for master-meter customers. SCE, TURN, and WMA engaged in settlement negotiations regarding the submetering discount. Ultimately, the RSC settlement adopts a submetering discount compromise that falls between the original proposals of SCE and TURN. The RSC settling parties also agreed that the RSC settlement resolves all issues relating to SCE's master meter discount and tariff language.[60]

8.1.5. TOU-D-PRIME as SCE's Primary Residential EV Rate and Marketing to EV Owners

During hearings on the RSC settlement, parties testified that the TOU-D-PRIME rate is intended to be the primary SCE rate for residential EV customers.[61] Because of the importance of widespread transportation electrification as a state policy goal,[62] the ability of TOU-D-PRIME to help meet that goal must be assessed before the Commission may find the RSC settlement reasonable and in the public interest.

First, this decision considers whether the off-peak pricing included in the rate design is sufficient to incent fuel switching by residential customers and therefore increase the financial incentive for adoption of EVs.[63] This decision assumes that such incentives exist so long as the price of energy under an EV rate is lower than price of an equivalent amount of gasoline energy. Parties referred

[60] Motion to adopt RSC settlement at 11.

[61] Transcript at 300.

[62] D.18-05-040 at 7-12.

[63] There are many other incentives and norms that may drive EV purchases, but for the sake of simplicity in this rate design proceeding the Commission only considers the comparative financial impacts of fueling EVs versus gasoline-powered vehicles.

to a "rule of thumb" in comparing the price of electricity the price of gasoline where a cent/kWh in a given rate's price structure is roughly equivalent to paying 10 cents for a gallon of gasoline.[64] For example, if an EV customer charged their vehicle on a rate of 10 cents/kWh, this would be roughly equivalent to a gas-powered vehicle owner paying $1 for a gallon of gasoline.

The illustrative rates for TOU-D-PRIME included in the RSC settlement indicate that off-peak pricing will initially be at or below approximately 13 cents/kWh. Assuming this is roughly equivalent to paying $1.30/gallon of gasoline and given that the average price for a gallon of gasoline in California currently stands at $3.615/gallon,[65] this decision finds that the off-peak rate is sufficient to incent fuel switching behavior amongst consumers, and therefore incent some consumers to purchase EVs for reasons of fuel cost savings. This finding is in spite of the $12/month fixed charge and the illustrative peak rate of nearly 36 cents/kWh in the summer period.

At hearings, parties granted that SCE's current enrollment rate for EV customers on EV-specific rates is very low. This is apparently due to a number of factors, including the current availability of an opt-in EV rate solely for those customers with separate metering installed for EV charging.[66]

While the settling parties intend for TOU-D-PRIME to become the primary EV rate for SCE's residential customers, during hearings SCE granted that they have no specific targets for EV customer enrollment on TOU-D-PRIME. SCE

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[64] Transcript at 310-311.

[65] American Automobile Association's estimate of gas prices, as of August 10, 2018. Available at: https://gasprices.aaa.com/?state=CA. Last checked August 10, 2018.

[66] Transcript at 312.

stated that they intend to use newly-available information on the identity of EV owners in their territory to target marketing that may lead to higher rates of EV owner enrollment on TOU rates such as TOU-D-PRIME.[67]

While the Commission appreciates SCE's intention to increase their marketing targeted to EV owners, SCE must establish a target EV owner enrollment rate for TOU-D-PRIME given that widespread transportation electrification is an important state policy goal. SCE must set a target to enroll 30% of the estimated residential EV owners in its territory in TOU-D-PRIME, or TOU rates TOU-EV-1, TOU-D-A, and TOU-D-B,[68] by the time SCE files its next GRC Phase II application. In achieving this target SCE should coordinate its efforts with any ongoing work in other relevant forums, including the Commission's transportation electrification proceedings as well the California Air Resources Board's Low Carbon Fuel Standard. This will ensure that SCE has sufficient direction to target and resource its marketing efforts.

Achieving this target may trigger the "meet and confer" process outlined by the RSC settlement to consider revenue shifts that result from high enrollment in TOU-D-PRIME. While this decision does not modify the RSC settlement, the Commission wishes to make clear to settling parties that the state policy goal of widespread transportation electrification is a high priority, and parties should be mindful of creating any barriers to achieving that goal through the meet and confer process.

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[67] Transcript at 315-317.

[68] Enrollments in TOU rates TOU-D-T, TOU-D-4-9PM, and TOU-D-5-8PM shall not count toward the 30% target. These TOU rates utilize tiers and off-peak prices that do not support fuel switching as well as TOU rates TOU-EV-1, TOU-D-A, and TOU-D-B.

In order to realize the benefits of TOU-D-PRIME, it is necessary that residential customers be made aware of the new rate and understand the benefits it may provide them. This decision orders SCE to provide Energy Division with an information-only Tier 1 advice letter enclosing SCE's marketing material for the TOU-D-PRIME rate, the total customer enrollments in TOU-D-PRIME and other TOU rates segmented by rate, the bill impacts for customers that switch to TOU-D-PRIME, and the rate impact on non-TOU-D-PRIME residential customers due to customer enrollment on TOU-D-PRIME. This Tier 1 advice letter shall be filed annually by the end of 2019, 2020, 2021, and 2022.

8.1.6. Residential Affordability

In PG&E's recent GRC Phase II proceeding, the Commission concluded that as a matter of law California's investor-owned utilities should acknowledge the importance of affordability issues facing residential customers in their rate design proceedings and propose steps to address it.[69] That conclusion applies to this proceeding, as the conclusion in the PG&E GRC Phase II decision is relevant to all utilities and not simply PG&E.

In hearings, the settling parties argued that the affordability issues facing residential customers were addressed in this proceeding in two primary ways: 1) the MC/RA settlement reduces the average rate for the residential class, and 2) the increase in baseline quantities of energy to 60% of average residential use (the maximum allowed by statute) reduces bills for certain customers with medium and high amounts of electricity usage.[70]

[69] D.18-08-013, CoL 48.

[70] Transcript at 318-327. While the motion to adopt the RSC settlement suggests that low-usage customers will see the benefit of the increase in baseline quantities, it is actually those customers

Footnote continued on next page

The MC/RA settlement lowers the average retail rate faced by the residential class, and approval of that settlement ensures that residential bills will become somewhat more affordable as a result.

With respect to the baseline proposal in general, while the Commission agrees with settling parties that the increased baseline quantity will apparently address affordability for some customers, it will also have the effect of increasing low-usage bills by a small amount.[71] Therefore, while this decision does not find the baseline proposal unreasonable, the baseline proposal is not a comprehensive attempt to address residential affordability.

Settling parties granted that steps to increase enrollment in the Family Electric Rate Assistance (FERA) program were not contemplated by the RSC settlement.[72] The FERA program provides bill discounts of 12% to those SCE residential customers that have at least three household members and income between 200%-250% of the federal poverty guidelines. As in the recent PG&E GRC Phase II decision, this decision finds that the FERA program can help address residential affordability by reducing bills for low-income customers.

SCE granted that their FERA participation rate is very low, and currently stands at less than 10%.[73] SCE identified a lack of outreach to FERA customers as a primary driver of the low enrollment rate. Despite this, the RSC settlement proposes no measures to increase FERA enrollment.

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with usage beyond the existing baseline that will see the most benefits, as revealed by the discussion at hearings.

[71] Transcript at 322-326.

[72] Transcript at 329-330.

[73] Transcript at 330.

Given that FERA can help address residential affordability for some low-income customers, it is important that SCE increase FERA enrollment in order to ensure that affordability for its low-income residential customers is maximized. Ultimately, SCE should achieve a similar subscription level for FERA and for CARE given the similarities of the programs' goals and target customers.[74] As an interim target, SCE must increase its FERA enrollment rate to 50% by 2023. Within 120 days of the effective date of this decision, SCE must file a Tier 2 advice letter with the Commission setting out its plan to achieve this target, including, if appropriate, the reallocation of any unspent California Alternate Rates for Energy (CARE) program marketing funds on such a plan.[75] SCE must report on its progress toward meeting this target by filing information-only advice letters with Energy Division at the end of 2019, 2020, 2021, 2022, and 2023. Both the Tier 2 advice letter and the information-only advice letters must be served on the service lists for this proceeding and A.14-11-007, A.14-11-009, A.14-11-010, and A.14-11-011. This direction is also consistent with the recent passage of SB 1135 (Bradford, 2018), which authorizes California's investor-owned utilities (IOUs) to increase or expand marketing and outreach efforts regarding the FERA program beyond those in effect as of December 31, 2018.

At hearings, settling parties also agreed that there would be utility in SCE developing a model of essential electricity usage for its residential customers, in

[74] D.18-08-013, CoL 50 adopts an identical goal for PG&E.

[75] As in D.18-08-013, this decision finds that it is appropriate to reallocate CARE marketing funds to increase FERA participation so long as the reallocation is dedicated toward marketing that is co-branded for both the CARE and FERA programs.

order to determine if SCE's residential customers are meeting their basic electricity needs at a reasonable cost.[76] Development of such a model is not considered by the RSC settlement. The Commission recently held in the PG&E GRC Phase II decision that developing such a model was a useful tool in lieu of relying on the proxy of baseline quantities.[77]

In order to more proactively address affordability for residential customers, SCE must develop a study plan (including budget) for developing a model of what constitutes essential use for its residential customers. This decision finds that to encourage harmonization with other California utilities, this model should be designed along the same lines as recently adopted by D.18-08-013 in the recent PG&E GRC Phase II proceeding.[78]

Therefore, the SCE study plan must consider a model that uses research, both existing (information sources such as the Residential Appliance Saturation Survey and Experian data) and new direct customer surveys, to collect information on household size (in terms of both square footage and number of residents), building features (age, construction materials, insulation, etc.), and appliances (efficiency and usage) in order to better evaluate the essential electricity needs of SCE's residential customers. The model of essential usage must be able to specify the amount of essential usage in both summer and winter for residential customers separately in each of the hot climate zone (SCE climate zones 10, 13, 14, and 15), the warm climate zone (SCE climate zones 5 and 9), and the cool climate zone (SCE climate zones 6, 8, and 16). The study plan for the

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[76] Transcript at 338-342.

[77] D.18-08-013, CoL 51.

[78] D.18-08-013, OP 14.

development of this model must be submitted with SCE's next rate design window (RDW) or GRC Phase II application, whichever comes first. SCE shall consult with parties to this proceeding, if a party expresses interest, as well as PG&E, when developing this study plan. If the development of a model of essential usage is included in the scope of R.18-07-006 before SCE files its next RDW or GRC Phase II application, whichever comes first, then SCE is not required to file the study plan.

8.1.7. Interaction with Consolidated Residential RDW Proceedings (A.17-12-011)

At hearings, settling parties confirmed that approval of the residential TOU rates considered by the RSC settlement would not prejudice the consideration of some of the residential TOU rates in the consolidated residential RDW proceedings (A.17-12-011).[79] This decision confirms this understanding and holds that Commission approval of the RSC settlement in this proceeding in no way prejudices the outcome of the consolidated residential RDW proceedings. The rates eventually authorized by a Commission decision in the consolidated residential RDW proceedings may be substantially different from those authorized by this decision.

8.1.8. Default Rate for NEM 2.0 Customers

The scoping memo for this proceeding seeks to resolve the default TOU rate for SCE's NEM 2.0 customers. The RSC settlement essentially defers this issue to SCE's 2018 Rate Design Window (RDW) application. The RSC settlement states that if there is a gap in time between the implementation date of

[79] Transcript at 342-344.

this decision and the issuance of a final decision in the 2018 RDW, the default TOU rate for the NEM 2.0 residential customers will be TOU-D, Option 4-9 p.m.

8.1.9. Compliance with Senate Bill 711

SB 711 (Hill, 2017) amended Public Utilities Code Section 739 and requires the Commission to make efforts to minimize bill volatility for residential customers, including all-electric customers, by explicitly authorizing the Commission to make certain changes to gas and electric baselines.[80]

The motion to adopt the RSC settlement states that the settlement complies with Public Utilities Code Section 739(a)(1) generally, which implies that that RSC settlement complies with SB 711.[81] The testimony referred to by the motion states that increasing baseline quantities, as proposed by the RSC settlement, is permitted by Public Utilities Code Section 739.[82]

This decision finds that the RSC settlement complies with Public Utilities Code Section 739(a)(1), and that the settling parties have demonstrated that the proposed changes to baseline quantities will increase the amount of lower-priced electricity available to SCE's residential customers. As the Commission has considered changes to electric baselines and adopts them to address the affordability of electricity, this decision finds that the Commission's adoption of the RSC settlement complies with SB 711.

8.2. Small Commercial Rate Design

The small commercial rate design elements of the RSC settlement focus on four main issues: 1) the base rate for TOU-GS-1 customers, 2) a special rate for

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

81 Motion to adopt RSC settlement at 18.

82 SCE-4 at 34-35, also citing as hearsay TURN's testimony in A.16-06-013.

small commercial customers with energy storage systems, 3) marginal costs for "Three Phase" customers, and 4) the threshold for taking service on rate schedule TOU-GS-1. Other elements such as fixed charges and volumetric charges are not discussed here but are included in the terms of the RSC settlement.

8.2.1. TOU-GS-1 Rate Design

SCE's smallest commercial customers (i.e., those with less than 20kW peak demand in a month) are placed on a rate known as TOU-GS-1. SCE proposed to include a fixed monthly charge and volumetric energy charges, but no demand charges, for this rate. Parties differed on the precise differentials to use for the volumetric energy charges and the amount of the fixed charge; but eventually settled on a rate with the same structure as originally proposed by SCE.[83]

The illustrative rates for TOU-GS-1 include a fixed charge of nearly $11/month. This is a substantial decrease of more than 50% compared to the current fixed charge for TOU-GS-1 customers.

For those customers electing to take service on Option D of TOU-GS-1, there is an additional non-coincident demand charge of $10/kW and a summer peak demand charge of approximately $15/kW. Option D customers would, in exchange, see substantially reduced volumetric charges compared to Option E (the base TOU-GS-1 rate). In total, Option D customers would see 33% of distribution revenue recovery through time-differentiated charges – either demand charges or volumetric rates. This would increase the time-differentiation of distribution revenue recovery for small commercial customers substantially.[84] Such time-differentiation of distribution revenue recovery is in

[83] Motion to adopt RSC settlement at 11-12.

[84] RSC settlement at 23.

accord with the Commission's previous findings regarding state energy policy goals.[85]

8.2.2. Small Commercial Energy Storage Rate

While not originally proposed by SCE in this proceeding, the RSC settling parties agreed to create a special rate for small commercial customers with energy storage. This rate will have the same rate design as the base TOU-GS-1 rate (*i.e.,* Option E of TOU-GS-1), but will include a $24/month fixed charge and stronger differentials between peak and off-peak periods. Participants are required to have minimum energy storage capacity equal to the greater of 4.8kWh or at least 0.05% of the customer's annual kWh usage over the previous 12 months. Customers with less than 12 months of data must have at least 4.8kWh in energy storage capacity to enroll. Enrollment is capped at 15,000 customers in order to safeguard against potential revenue shifts.[86]

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85 *See* D.18-08-013 at 47-51.

86 Motion to adopt RSC settlement at 12-13.

8.2.3. Marginal Costs for "Three Phase" Customers

The RSC settlement proposes to set the customer charge for so-called "Three Phase" small commercial customers at $0.93/month. This figure is the result of a compromise approach on marginal costs that essentially splits the difference between the proposals offered by SCE and ORA in testimony.[87] Three phase customers apparently have a higher cost-basis than single phase customers due to the different distribution facilities required by these customers.[88]

8.2.4. Threshold for Small Commercial Customers

SCE currently defines a small commercial customer eligible for service on TOU-GS-1 as one with a peak demand of 20kW or less per month. Settling parties discussed the possibility of increasing this threshold to align with the practice of other California utilities. As a part of the RSC settlement, SCE will conduct a study on whether its current TOU-GS-1 rate class should be expanded to include customers with monthly peak demands in excess of 20kW. SCE agreed to include the results of this study as part of its 2021 GRC Phase II application.[89]

8.2.4. Food Bank Rate

To comply with Assembly Bill (AB) 2218 (Bradford, 2014) and Public Utilities Code Section 739.3, the RSC settlement proposes that SCE implement a new food bank rate assistance program by providing eligible food banks a 20%

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[87] Motion to adopt RSC settlement at 13.

[88] RSC settlement at 24.

[89] Motion to adopt RSC settlement at 13-14.

discount on their bill.[90] This proposal mirrors the food bank rate recently adopted for PG&E in D.18-08-013.

8.3. Findings Regarding the RSC Settlement

The Commission's standard of review for uncontested settlements appears in Section 2 above. The Commission must review the RSC settlement to determine if it is reasonable in light of the whole record, consistent with law, and in the public interest. The Commission reviewed the RSC settlement's terms, and an ALJ assigned to this proceeding examined a panel of witnesses testifying on behalf of the settlement in evidentiary hearings on August 10, 2018. This decision finds that the RSC settlement should be approved for reasons including the following:

- The creation of optional TOU rates for residential and small commercial customers with time-differentiated distribution charges comports with recent Commission decisions (D.17-01-006, D.17-08-030, and D.18-08-013) requiring a menu of rate options for customers, and greater time-differentiation of distribution charges generally.
- The creation of an optional TOU rate to incent residential adoption of electric vehicles comports with state policy to increase transportation electrification, and is therefore in the public interest.
- The RSC settlement allows legacy solar customers to remain on their existing TOU rate structures for an appropriate period of time, as defined by previous Commission decisions.
- The food bank rate matches previously adopted food bank rates for other utilities and complies with AB 2218.

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[90] RSC settlement at 30.

- The RSC settlement is reasonable in light of the whole record as it represents compromise positions between the settling parties relative to the positions taken in their testimony.
- The RSC settlement does not violate existing law or previous Commission decisions.

SCE must implement the terms of the RSC settlement as soon as practicable after the issuance of this decision.

9. Settlement on RES-BCT Mitigation Measures

SCE filed a motion to adopt the RES-BCT[91] indifference mechanism settlement agreement on August 6, 2018. SCE filed a motion seeking Commission approval of an amended RES-BCT indifference mechanism settlement agreement (RES-BCT settlement) on September 28, 2018. The latter motion asked the Commission to consider the amended RES-BCT settlement as superseding the originally filed RES-BCT settlement, and this decision does so. The amended RES-BCT settlement is the RES-BCT settlement considered for purposes of this decision. The original RES-BCT settlement motion of August 6, 2018 is disregarded as moot.

The parties to the RES-BCT settlement are SCE and the renewable energy water districts (REWD). REWD represents two of the 18 eligible SCE customers currently receiving RES-BCT service in SCE's territory, the Santa Clarita Valley Water Agency (SCVWA), as the successor-in-interest to the Castaic Lake Water Agency (CLWA), and the Rancho California Water District (RCWD). Both

[91] RES-BCT stands for Renewable Energy Self-Generation Bill Credit Transfer program. This program, created by statute, allows local governmental entities to offset several of their utility bills with revenue generated by a single renewable generation facility.

SCVWA and RCWD are government agencies who are bundled service customers of SCE and take service on SCE's RES-BCT tariffs. The 16 eligible customers not represented by REWD and currently receiving RES-BCT service in SCE's territory are eligible to accept the RES-BCT settlement's mitigation measures if they choose.[92] No other party joined or opposed the settlement, and therefore the settlement is uncontested.

The RES-BCT settlement arises from negotiations conducted pursuant to D.18-07-006, which required SCE and REWD to work collaboratively in this proceeding to develop an indifference mechanism that, by mutual agreement, will have the result that SCE's RES-BCT program continues to be a viable mechanism for the governmental entities that currently participate in the program.[93] Therefore, in addition to the Commission's standard of review for settlements as outlined in Section 2, this decision must also evaluate whether the settlement complies with the instructions of D.18-07-006.

9.1. Consistency with Treatment of NEM Customers as a Test of Viability

There are many ways to assess whether a given incentive program creates viability for an industry. This decision examines the consistency of treatment afforded by the RES-BCT settlement to RES-BCT customers as compared to the

[92] In addition to the 18 currently eligible RES-BCT customers, SCE identified 15 not-yet-operational customers who are eligible for RES-BCT grandfathering pursuant to D.17-01-006 and therefore may accept the RES-BCT's mitigation measures if they eventually become operational. These not-yet-operational customers would not be entitled to the same mitigation measures as currently operational customers, as defined by the RES-BCT settlement. REWD represents two of the 15 not-yet-eligible customers: Eastern Municipal Water District (EMWD) and Las Virgenes Municipal Water District (LVMWD).

[93] D.18-07-006, Ordering Paragraph 3.

treatment afforded to NEM customers by the TOU settlement in order to determine viability.

The compromise contained in the TOU settlement reflects the judgment of varied stakeholders on how to ensure that investments in NEM systems by SCE customers remain viable in the coming years. This compromise, which this decision approves, establishes a baseline for the appropriate mitigation due SCE's legacy solar customers as they are transitioned to new TOU peak periods.

The RES-BCT settlement also considers mitigation owed to legacy solar customers, and therefore should be compared to the TOU settlement to determine if it creates a viable RES-BCT program.

At hearings, settling parties stated that the mitigation measures afforded RES-BCT customers by the RES-BCT settlement were similar to the mitigation afforded NEM customers through the rate designs set out by the TOU settlement.[94] A workpaper prepared by SCE to determine this similarity was served in this proceeding on August 29, 2018, and it reveals that the RES-BCT settlement affords mitigation similar to that afforded to NEM customers through the TOU settlement.[95]

9.2. Findings Regarding the RES-BCT settlement

The Commission's standard of review for uncontested settlements appears in Section 2 above. The Commission must review the RES-BCT settlement to determine if it is reasonable in light of the whole record, consistent with law

[94] Transcript at 283-284.

[95] SCE-8 at 7, showing that after indifference payments are made to legacy RES-BCT customers the reduction in the value of exported solar energy will be similar to that faced by NEM customers under the terms of the TOU settlement.

(including being consistent with the instructions given in D.18-07-006), and in the public interest. The Commission reviewed the RES-BCT settlement's terms, and an ALJ assigned to this proceeding examined a panel of witnesses testifying on behalf of the settlement in evidentiary hearings on August 10, 2018. This decision finds that the RES-BCT settlement should be approved for reasons including the following:

- Workpapers prepared by SCE reveal that RES-BCT legacy solar customers will be treated equivalently to NEM customers, which ensures program viability for current RES-BCT customers.
- The RES-BCT settlement complies with the instructions of D.18-07-006.
- The RES-BCT settlement represents a compromise of positions taken by SCE and REWD, and is therefore reasonable in light of the whole record.
- The RES-BCT settlement provides safeguards against abuse of the settlement's mitigation measures by preventing transfers to NEM service or non-legacy rates after an RES-BCT customer receives a mitigation payment.
- The RES-BCT settlement is in the public interest as it ensures that solar energy investments made by local government entities continue to receive support through a statutorily-mandated program.

SCE must implement the terms of the RES-BCT settlement as soon as practicable after the issuance of this decision.

10. Agricultural Rate Design

On August 3, 2018 SCE filed a motion to adopt a settlement on agricultural and pumping rate group rate design (A&P settlement). The A&P settlement is between SCE, CFBF, and AECA. These are the only parties to serve testimony on A&P rate design issues, and therefore the settlement is uncontested.

The A&P settlement resolves several issues related to A&P rate design, including rate elements and rate options, treatment of legacy solar A&P customers, mitigation measures for non-solar A&P customers transitioning to new TOU periods, enhanced marketing, and certain uncontested SCE tariff rule modifications.[96]

10.2. A&P Rate Elements and Rate Options

The settling parties agreed that A&P customers will continue to face a combination of customer charges, energy charges, and demand charges (both coincident and non-coincident). Optional real-time pricing rates will also remain available for A&P customers.

The A&P settlement maintains the current level of customer charges, and energy charges by TOU period will be "smoothed" in order to accommodate transitions to new TOU periods.[97] A new summer on-peak coincident demand charge is introduced by the A&P settlement to begin time-differentiation of distribution costs. To offer a menu of rate options to A&P customers, Option E for TOU-PA-2 and TOU-PA-3 will not include coincident demand charges, but will include non-coincident demand charges.

The A&P settlement also closes the existing "SOP"[98] rate options for TOU-PA-2 and TOU-PA-3 customers, while allowing existing SOP customers to transfer to legacy solar rate structures.

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[96] Motion to adopt A&P settlement at 3.

[97] Motion to adopt A&P settlement at 6.

[98] SOP stands for super off-peak. SOP customers enjoyed specific rate options that allowed for super off-peak pricing during certain hours (e.g., 12 a.m. – 6 a.m.).

10.3. Treatment of Legacy Solar A&P Customers

As noted previously in this decision, legacy solar A&P customers were excluded from the terms of the TOU settlement. The A&P settlement resolves issues related to legacy solar A&P customers and their transition to new TOU periods.

Eligibility for legacy solar rates is limited to those legacy solar A&P customers that are due eligibility per D.17-01-006 and D.17-10-018. The legacy solar rates maintain the existing TOU periods, but the underlying rates will change over time.

10.4. Mitigation Measures for Non-Solar A&P Customers Transitioning to New TOU Periods

The A&P settlement addresses mitigation for non-solar A&P customers transitioning to new TOU peak periods by including the following measures:

- A menu of rate options that specifically includes an earlier end to the peak period to address safety and operational concerns.
- Personalized outreach to customers with bill impacts exceeding 5% (minimum $50/month).
- Personalized outreach to any existing SOP customer with a negative bill impact.

10.5. Enhanced Marketing and Outreach

The A&P settlement obliges SCE to develop an A&P-specific marketing and outreach plan in connection with its implementation of new TOU periods and the updated A&P rate designs. This plan will be developed with the input of A&P stakeholders.

10.6. Findings Regarding the A&P Settlement

The Commission's standard of review for uncontested settlements appears in Section 2 above. The Commission must review the A&P settlement to determine if it is reasonable in light of the whole record, consistent with law, and in the public interest. The Commission reviewed the A&P settlement's terms, and this decision finds that the A&P settlement should be approved for reasons including the following:

- The terms of the A&P settlement represent compromise positions of the parties that submitted testimony on A&P rate design issues, and the settlement is therefore reasonable in light of the whole record.
- The A&P settlement's provisions with respect to legacy solar customers complies with previous Commission decisions.
- The A&P settlement's mitigation measures for non-solar customers adversely affected by the transition to new TOU periods, including the creation of an optional rate with an 8:00 p.m. end to the peak period, are in the public interest.

SCE must implement the terms of the A&P settlement as soon as practicable after the issuance of this decision.

11. Conclusion

This decision adopts rate designs and resolves related issues for SCE considered in A.17-06-030. This decision approves all of the settlements filed in this proceeding and creates two main forms of rate design for SCE's non-residential customers: Option D rates and Option E rates. This decision also orders SCE to develop a model of essential usage for its residential customers, set an interim FERA enrollment target of 50% and propose steps to reach that target, and prepare a dimmable streetlight rate and program for the Commission's consideration in its next GRC Phase II application.

12. Outstanding Procedural Matters

The Commission affirms all rulings made by the assigned Commissioner and assigned ALJs. All motions not previously ruled on are deemed denied.

13. Comments on Proposed Decision

The proposed decision of Administrative Law Judge Patrick Doherty in this matter was mailed to the parties in accordance with Pub. Util. Code § 311, and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on November 8, 2018, 2018, by the following parties: SCE, SBUA, and jointly by AECA, CFBF, CLECA, CMTA, FEA, EPUC, and EUF. Changes to the proposed decision have been made throughout in response to comments.

14. Assignment of Proceeding

Carla J. Peterman is the assigned Commissioner and Michelle Cooke and Patrick Doherty are the assigned ALJs in this proceeding.

Findings of Fact

1. The parties to the MC/RA settlement did not agree on which marginal costs to use in allocating revenue among SCE's customer classes. Instead, they focused on the revenue allocation that they believed was reasonable given a range of marginal cost values, and then agreed to marginal cost values that would result in the desired revenue allocation outcome.

2. The artificial marginal costs used in the MC/RA settlement are considered to be reasonable by the parties. This is because the artificial marginal costs fall within the range of those originally proposed by the parties, and according to witnesses are values that survived rejection by the parties, rather than values that were acceptable in and of themselves.

3. The MC/RA settlement ultimately proposes to adopt marginal costs and allocate revenue among SCE's customer classes such that all bundled SCE customers are forecasted to experience lower average rates.

4. The development of functional splits of SCE's marginal generation costs and distribution costs may have implications in other Commission proceedings.

5. Parties representing all customer groups presented testimony on revenue allocation issues and participated in MC/RA-related settlement negotiations.

6. Parties worked diligently and focused on multiple simulations of marginal cost and revenue allocation impacts, and ultimately agreed to focus on the reasonableness of the MC/RA settlement's revenue allocation rather than marginal cost responsibility.

7. Setting the EDR discount at a standard rate of 12% will ensure that EDR customers cover their marginal costs and responsibilities for non-bypassable charges.

8. SCE's existing EDR program resulted in the historic attraction and retention of thousands of jobs in SCE's territory by EDR customers.

9. The parties to the streetlight rate design settlement bargained in good faith and sought compromises among their litigated positions.

10. The testimony of CAL-SLA in this proceeding reveals that dimmable streetlight systems have public benefits such as increased conservation, reduced greenhouse gas emissions, and public safety applications.

11. The testimony of CAL-SLA reveals that municipalities within SCE's service territory are actively working toward making their streetlights dimmable.

12. The TOU settlement creates some measure of rate certainty for legacy solar customers, while limiting the cost shifts imposed on other non-legacy solar customers.

13. Widespread transportation electrification is an important state policy goal.

14. The TOU-D-PRIME rate is intended to be the primary SCE rate for residential EV customers.

15. The off-peak rate of TOU-D-PRIME is sufficient to incent fuel switching behavior amongst consumers, and therefore incent some consumers to purchase EVs for reasons of fuel cost savings.

16. SCE's current enrollment rate for EV customers on EV-specific rates is very low. This is apparently due to a number of factors, including the current availability of an opt-in EV rate solely for those customers with separate metering installed for EV charging.

17. SCE has no specific targets for EV customer enrollment on TOU-D-PRIME. SCE intends to use newly-available information on the identity of EV owners in their territory to target marketing that may lead to higher rates of EV owner enrollment on TOU rates such as TOU-D-PRIME.

18. The MC/RA settlement lowers the average retail rate faced by the residential class, and approval of that settlement ensures that residential bills will become somewhat more affordable as a result.

19. The FERA program can help address residential affordability by reducing bills for low-income customers.

20. Parties to the RSC settlement granted that steps to increase enrollment in the FERA program were not contemplated by the RSC settlement.

21. SCE's FERA participation rate is very low, and currently stands at less than 10% of eligible customers. SCE identified a lack of outreach to FERA customers as a primary driver of the low enrollment rate.

22. At hearings, parties to the RSC settlement agreed that there would be utility in SCE developing a model of essential electricity usage for its residential customers, in order to determine if SCE's residential customers are meeting their basic electricity needs at a reasonable cost. The Commission recently held in the PG&E GRC Phase II decision that developing such a model was a useful tool in lieu of relying on the proxy of baseline quantities.

23. The compromise contained in the TOU settlement reflects the judgment of varied stakeholders on how to ensure that investments in NEM systems by SCE customers remain viable in the coming years. This compromise, which this decision approves, establishes a baseline for the appropriate mitigation due SCE's legacy solar customers as they are transitioned to new TOU peak periods.

24. The MLP settlement's Option E rates help to achieve some of the goals of the Commission's DER action plan.

25. The RES-BCT settlement also considers mitigation owed to legacy solar customers, and therefore should be compared to the TOU settlement to determine if it creates a viable RES-BCT program.

26. Workpapers prepared by SCE reveal that RES-BCT legacy solar customers will be treated equivalently to NEM customers, which ensures program viability for current RES-BCT customers.

Conclusions of Law

1. The Commission's preferred starting point for analyzing the reasonableness of a utility's revenue allocation is to assess whether it complies with the EPMC methodology.

2. The Commission's view is that EPMC is a transparent and fair way of allocating revenue responsibility among a utility's customer classes, assuming that marginal costs can be established.

3. It is reasonable for the Commission to accept the use of artificial marginal cost values for the purpose of revenue allocation and rate design, so long as those values are within the range of alternatives offered by the parties in their testimony.

4. The Commission must review settlements to determine if they are reasonable in light of the whole record, consistent with law, and in the public interest.

5. The MC/RA settlement is not contrary to any law or previous Commission decision.

6. The marginal costs adopted by the MC/RA settlement, while not subject to full Commission review, are apparently within the range of values proposed by the parties, and are therefore reasonable in light of the whole record.

7. The MC/RA settlement's revenue allocation is a balanced outcome that leads to reductions in average rates for ratepayers, and is therefore in the public interest.

8. The modifications to the EDR program made by the EDR settlement are reasonable in light of the whole record as they represent a compromise among the EDR positions established by settling parties in their prepared testimony.

9. The expansion of the affidavit requirement to all of SCE's EDR applicants will enhance the safeguards that aim to prevent cost-shifting, and is therefore in the public interest.

10. The EDR settlement's terms are consistent with the law and in the public interest as the historic attraction and retention of thousands of jobs in SCE's territory by EDR customers confers sufficient ratepayer benefits to justify the continuation of SCE's EDR program per Public Utilities Code Section 740.4(h).

11. The EDR settlement is in the public interest as the agreement is a reasonable compromise between stakeholders representing a broad range of interests.

12. The illustrative rates for streetlight rate group customers that result from the streetlight rate design settlement, in particular customer charges for AL-2 and LS-3 customers, reflect modest increases and decreases to most rate components, making the rate changes reasonable and in the public interest.

13. The provisions of the streetlight rate design settlement are not contrary to law.

14. SCE's implementation of a pole-mounted rate option for certain streetlight rate group customers, and outreach to eligible customers, is in the public interest as it expands rate options for certain customers.

15. As in the recent decision in PG&E's recent GRC Phase II, this decision finds that a dimmable streetlight system for streetlight customers is in the public interest and should be pursued expeditiously.

16. The TOU settlement is in the public interest as it is a reasonable compromise of positions taken by parties that represent the interests of a wide variety of customers that are affected by the terms of the TOU settlement.

17. The TOU settlement complies with the terms of D.17-01-006 and D.17-10-018 and is therefore consistent with the law on this issue.

18. The TOU settlement is reasonable in light of the whole record as it largely adopts positions taken by parties in their testimony or adopts compromises of those positions.

19. In order to provide a true menu of rate options, and therefore comply with previous Commission decisions, it is necessary that MLP customers be made aware of Option E and understand the benefits it may provide them.

20. The MLP settlement shifts a large portion of distribution cost recovery to time-dependent demand and energy charges, in accord with the Commission's rate design principles and recent decisions in other electric utility GRC Phase II proceedings (D.17-08-030 and D.18-08-013). The MLP settlement also creates rate options for MLP customers that are in accord with the direction in D.17-01-006. The MLP settlement therefore complies with the law and is in the public interest.

21. The MLP settlement's treatment of EV rates is reasonable given that the primary EV rates for MLP customers are governed by the Transportation Electrification proceeding and not by this GRC Phase II proceeding.

22. As the MLP settlement is uncontested and is agreed to by all the parties that submitted testimony on MLP rate design issues, and because certain elements of the MLP settlement represent the product of arms-length negotiation and compromise between those parties, the MLP settlement is reasonable in light of the whole record.

23. In order to realize the benefits of TOU-D-PRIME, it is necessary that residential customers be made aware of the new rate and understand the benefits it may provide them.

24. As a matter of law California's investor-owned utilities should acknowledge the importance of affordability issues facing residential customers in their rate design proceedings and propose steps to address it.

25. Ultimately, SCE should achieve a similar subscription level for FERA and for CARE given the similarities of the programs' goals and target customers.

26. This decision's direction to SCE with respect to FERA is consistent with the recent passage of Senate Bill 1135 (Bradford, 2018), which authorizes California's IOUs to increase or expand marketing and outreach efforts regarding the FERA program beyond those in effect as of December 31, 2018.

27. Commission approval of the RSC settlement in this proceeding in no way prejudices the outcome of the consolidated residential RDW proceedings.

28. The RSC settlement complies with Public Utilities Code Section 739(a)(1), and the RSC settling parties have demonstrated that the proposed changes to baseline quantities will increase the amount of lower-priced electricity available to SCE's residential customers. As the Commission has considered changes to electric baselines and adopts them to address the affordability of electricity, the Commission's adoption of the RSC settlement complies with SB 711.

29. The creation of optional TOU rates for residential and small commercial customers with time-differentiated distribution charges comports with recent Commission decisions (D.17-01-006, D.17-08-030, and D.18-08-013) requiring a menu of rate options for customers, and greater time-differentiation of distribution charges generally.

30. The creation of an optional TOU rate to incent residential adoption of electric vehicles comports with state policy to increase transportation electrification, and is therefore in the public interest.

31. The RSC settlement allows legacy solar customers to remain on their existing TOU rate structures for an appropriate period of time, as defined by previous Commission decisions.

32. The food bank rate as proposed in the RSC settlement matches previously adopted food bank rates for other utilities and complies with AB 2218.

33. The RSC settlement is reasonable in light of the whole record as it represents compromise positions between the settling parties relative to the positions taken in their testimony.

34. The RSC settlement does not violate existing law or previous Commission decisions.

35. D.18-07-006 required SCE and REWD to work collaboratively in this proceeding to develop an indifference mechanism that, by mutual agreement, will have the result that SCE's RES-BCT program continues to be a viable mechanism for the governmental entities that currently participate in the program.

36. This decision examines the consistency of treatment afforded by the RES-BCT settlement to RES-BCT customers as compared to the treatment afforded to NEM customers by the TOU settlement in order to determine program viability.

37. The RES-BCT settlement complies with the instructions of D.18-07-006.

38. The RES-BCT settlement represents a compromise of positions taken by SCE and REWD and is therefore reasonable in light of the whole record.

39. The RES-BCT settlement provides safeguards against abuse of the settlement's mitigation measures by preventing transfers to NEM service or non-legacy rates after a RES-BCT customer receives a mitigation payment.

40. The RES-BCT settlement is in the public interest as it ensures that solar energy investments made by local government entities continue to receive support through a statutorily-mandated program.

41. The terms of the A&P settlement represent compromise positions of the parties that submitted testimony on A&P rate design issues, and the settlement is therefore reasonable in light of the whole record.

42. The A&P settlement's provisions with respect to legacy solar customers complies with previous Commission decisions.

43. The A&P settlement's mitigation measures for non-solar customers adversely affected by the transition to new TOU periods, including the creation

of an optional rate with an 8 p.m. end to the peak period, are in the public interest.

O R D E R

IT IS ORDERED that:

1. All motions filed by Southern California Edison Company in this proceeding seeking adoption of settlement agreements are granted, with the exception of the motion of August 6, 2018 seeking adoption of the original Renewable Energy Self-Generation Bill Credit Transfer indifference adjustment mechanism settlement agreement.

2. Southern California Edison Company shall include Pacific Gas and Electric Company and San Diego Gas & Electric Company as participants in the working group process set out by the settlement on marginal costs and revenue allocation.

3. Southern California Edison Company must implement the terms of the settlement on marginal costs and revenue allocation as soon as practicable after the issuance of this decision.

4. Southern California Edison Company must implement the terms of the Economic Development Rate settlement as soon as practicable after the issuance of this decision.

5. Southern California Edison Company must implement the terms of the streetlight rate design settlement as soon as practicable after the issuance of this decision.

6. Southern California Edison Company must propose a dimmable streetlight rate option in its next General Rate Case Phase II application for Commission consideration.

7. Southern California Edison Company must implement the terms of the settlement agreement on Time-Of-Use period mitigation for solar grandfathered commercial and industrial customers as soon as practicable after the issuance of this decision.

8. Southern California Edison Company must file an information-only advice letter if the total customer load served by medium and large commercial Option E customers that qualify for Option E due to their charging of zero-emission vehicles exceeds the total customer load on rates TOU-EV-8 and TOU-EV-9.

9. Southern California Edison Company (SCE) must file an information-only Tier 1 advice letter enclosing:

- SCE's marketing material for the Option E rates for medium and large commercial customers,
- the total customer enrollments in Option E in each of the TOU-GS-2, TOU-GS-3, and TOU-8 tariffs,
- the bill impacts for customers that switch to Option E, and
- the rate impact on non-Option E customers due to customer enrollment on Option E in each of the TOU-GS-2, TOU-GS-3, and TOU-8 tariffs.

This Tier 1 advice letter shall be filed annually by the end of 2019, 2020, 2021, and 2022.

10. Southern California Edison Company must implement the terms of the settlement agreement on rate design for the medium and large power rate group as soon as practicable after the issuance of this decision.

11. Southern California Edison Company (SCE) must file an information-only Tier 1 advice letter enclosing:

- SCE's marketing material for the TOU-D-PRIME rate for residential customers,
- the total customer enrollments in TOU-D-PRIME and other Time-of-Use rates segmented by rate,
- the bill impacts for customers that switch to TOU-D-PRIME, and
- the rate impact on non-TOU-D-PRIME residential customers due to customer enrollment in TOU-D-PRIME.

This Tier 1 advice letter shall be filed annually by the end of 2019, 2020, 2021, and 2022.

12. Southern California Edison Company (SCE) is directed to set a target to enroll 30% of the estimated residential electric vehicle owners in its territory in TOU-D-PRIME, or Time-of-Use rates TOU-EV-1, TOU-D-A, and TOU-D-B, by the time SCE files its next General Rate Case Phase II application.

13. As an interim target, Southern California Edison Company (SCE) must increase its Family Electric Rate Assistance (FERA) program enrollment rate to 50% of eligible customers by 2023. Within 120 days of the effective date of this decision, SCE must file a Tier 2 advice letter with the Commission setting out its plan to achieve this target, including, if appropriate, the reallocation of any unspent California Alternate Rates for Energy (CARE) program marketing funds on such a plan. SCE must report on its progress toward meeting this target by filing information-only advice letters with Energy Division at the end of 2019, 2020, 2021, 2022, and 2023. Both the Tier 2 advice letter and the information-only advice letters must be served on the service lists for this proceeding and Application (A.) 14-11-007, A.14-11-009, A.14-11-010, and A.14-11-011.

14. Southern California Edison Company (SCE) must develop a study plan (including budget) for developing a model of what constitutes essential use for

its residential customers. The SCE study plan must consider a model that uses research, both existing (information sources such as the Residential Appliance Saturation Survey and Experian data) and new direct customer surveys, to collect information on household size (in terms of both square footage and number of residents), building features (age, construction materials, insulation, etc.), and appliances (efficiency and usage) in order to better evaluate the essential electricity needs of SCE's residential customers. The model of essential usage must be able to specify the amount of essential usage in both summer and winter for residential customers separately in each of the hot climate zone (SCE climate zones 10, 13, 14, and 15), the warm climate zone (SCE climate zones 5 and 9), and the cool climate zone (SCE climate zones 6, 8, and 16). The study plan for the development of this model must be submitted with SCE's next rate design window (RDW) or General Rate Case (GRC) Phase II application, whichever comes first. SCE shall consult with parties to this proceeding, if a party expresses interest, as well as Pacific Gas and Electric Company, when developing this study plan. If the development of a model of essential usage is included in the scope of Rulemaking 18-07-006 before SCE files its next RDW or GRC Phase II application, whichever comes first, then SCE is not required to file the study plan.

15. Southern California Edison Company must implement the terms of the settlement agreement on residential and small commercial rate design as soon as practicable after the issuance of this decision.

16. Southern California Edison Company must implement the terms of the Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) indifference mechanism settlement agreement as soon as practicable after the issuance of this decision.

17. Southern California Edison Company must implement the terms of the settlement on agricultural and pumping rate group rate design as soon as practicable after the issuance of this decision.

18. All outstanding motions are denied.

19. Application 17-06-030 is closed.

This order is effective today.

Dated November 29, 2018, at San Francisco, California.

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