STATE OF CALIFORNIA GAVIN NEWSOM

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

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June 17, 2022

**Agenda ID #20725**
**Ratesetting**

TO PARTIES OF RECORD IN APPLICATION 20-10-012:

This is the proposed decision of Administrative Law Judge Douglas Long. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's August 4, 2022 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

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

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.2(c)(4).

/s/ ANNE E. SIMON

Anne E. Simon
Chief Administrative Law Judge

AES:nd3
Attachment

Decision **PROPOSED DECISION OF ALJ LONG (Mailed 6/17/2022)**

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

| | |
|---|---|
| Application of Southern California Edison Company (U338E) to Establish Marginal Costs, Allocate Revenues, and Design Rates. | Application 20-10-012 |

# DECISION ADOPTING FIVE UNCONTESTED PARTIAL SETTLEMENTS RESOLVING MOST ISSUES FOR SOUTHERN CALIFORNIA EDISON COMPANY'S PHASE 2 GENERAL RATE CASE

**TABLE OF CONTENTS**

**Title** **Page**

DECISION ADOPTING FIVE UNCONTESTED PARTIAL SETTLEMENTS RESOLVING MOST ISSUES FOR SOUTHERN CALIFORNIA EDISON COMPANY'S PHASE 2 GENERAL RATE CASE ........ 1
Summary ........ 2
1. Background ........ 3
1.1. Procedural Background ........ 3
2. Issues Before the Commission ........ 5
3. Settlements Generally ........ 6
3.1. Standard of Review ........ 6
3.1.1. Conclusion ........ 7
4. Specific Settlements ........ 8
4.1. The Marginal Cost and Revenue Allocation Settlement Agreement ........ 8
4.1.1. Generation Capacity Marginal Costs ........ 10
4.1.2. Generation Marginal Energy Costs ........ 11
4.1.3. Customer Marginal Costs Methods ........ 11
4.1.4. Distribution Design Demand Marginal Costs ........ 12
4.1.5. Sales Forecast ........ 12
4.1.6. Capping and Collaring ........ 13
4.1.7. Wildfire-Related Revenue Requirement ........ 13
4.1.8. Transportation Electrification Allocation ........ 16
4.1.9. Other Issues ........ 16
4.1.10. Conclusion and Adoption of the Settlement ........ 17
4.2. The Residential and Small Commercial Rate Design Settlement Agreement ........ 17
4.2.1. Conclusion and Adoption of the Settlement ........ 21
4.3. The Streetlight and Traffic Control Rate Group Settlement Agreement ........ 21
4.3.1. Non-Allocated Revenues ........ 22
4.3.2. Energy Charges and Customer Charges ........ 23
4.3.3. Schedule Residential Walkway Lighting ........ 23
4.3.4. Streetlighting LED Conversion ........ 23
4.3.5. Dimmable Streetlighting Pilot ........ 24
4.3.6. 90-Day Streetlight Stop Billing ........ 25
4.3.7. Ancillary Device Rate Design ........ 25
4.3.8. Conclusion and Adoption of the Settlement ........ 26

4.4. The Agricultural and Pumping Rate Group Rate Design Settlement Agreement ........ 26
4.4.1. Common Rate Design Elements and Agricultural and Pumping Rate Options ........ 27
4.4.2. Time Management Load Controller Devices ........ 28
4.4.3. Removal of Pay-As-You-Grow Special Condition ........ 28
4.4.4. Conclusion and Adoption of the Settlement ........ 28
4.5. Medium and Large Power Rate Group Rate Design Settlement Agreement ........ 29
4.5.1. Demand Charges ........ 29
4.5.1.1. Time Related Demand Charges ........ 29
4.5.1.2. Facilities Related Demand Charges ........ 30
4.5.2. Base and Optional Rates and Rate Design (Non-Standby) ........ 30
4.5.2.1. Option D Base Rate — Eligibility Requirements and Rate Design ........ 30
4.5.2.1.1. TOU-GS-2 and TOU-GS-3 ........ 30
4.5.2.1.2. Option D TOU-8 and TOU-8-PRI ........ 31
4.5.2.2. Option E Optional Rate — Eligibility and Rate Design ........ 32
4.5.2.2.1. TOU-GS-2 and TOU-GS-3 ........ 32
4.5.2.2.2. Option E TOU-8 ........ 33
4.5.3. Attrition Year DER Class Study ........ 33
4.5.4. Default Critical Peak Pricing Rate Design ........ 34
4.5.5. Legacy Option B and Option R (Option A and Option B for Standby) ........ 34
4.5.6. Standby Rate Design ........ 34
4.5.7. EV Rate Design ........ 35
4.5.8. RTP Rate Options ........ 36
4.5.9. Reliability Back-Up Service Rate Design (TOU-8-RBU) ........ 36
4.5.10. Closing of Schedule GS-2 (Flat Rate) ........ 37
4.5.11. Demand Response Credits (BIP and APS) ........ 37
4.5.12. Attrition Year Changes ........ 37
4.5.13. Conclusion and Adoption of the Settlement ........ 38
5. Environmental and Social Justice Action Plan ........ 38
6. California Environmental Quality Act ........ 39
7. Safety ........ 39
8. Conclusion ........ 39
9. Comments on Proposed Decision ........ 40
10. Assignment of Proceeding ........ 40

Findings of Fact....................40
Conclusions of Law....................41
ORDER....................43

# DECISION ADOPTING FIVE UNCONTESTED PARTIAL SETTLEMENTS RESOLVING MOST ISSUES FOR SOUTHERN CALIFORNIA EDISON COMPANY'S PHASE 2 GENERAL RATE CASE

## Summary

This decision adopts five separate and uncontested partial settlements resolving distinct and specific components of Southern California Edison Company's (SCE) proposals for establishing marginal costs, the allocation of revenues, and rate designs to be used to prospectively recover SCE's revenue requirements as adopted by the Commission. These five settlements are each independent of the other, adopted and found to be reasonable, and to be in the public interest on their own individual merits, pursuant to Rule 12.1 of the Commission's Rules of Practice and Procedure and applicable statutes. They are:

1. The Marginal Cost and Revenue Allocation Settlement Agreement, filed on December 13, 2021;
2. The Residential and Small Commercial Rate Design Settlement Agreement, filed on December 17, 2021;
3. The Streetlight and Traffic Control Rate Group Settlement Agreement, filed on January 7, 2022;
4. The Agricultural and Pumping Rate Group Rate Design Settlement Agreement, filed on January 11, 2022; and
5. The Medium and Large Power Rate Group Rate Design Settlement Agreement, filed on February 18, 2022.

All issues contemplated in the scoping memo for this proceeding are resolved by the five separately filed settlements except for specific real-time pricing and several other issues which are still to be resolved. The changes to marginal cost, cost allocation, and rate design that we adopt as part of these settlements are not precedential. Therefore, SCE must present a full and persuasive showing for its next marginal cost, cost allocation and rate design

proposal and for any changes in these adopted settlements that are also included in SCE's next phase 2 general rate case filing.

This proceeding does not change SCE's authorized revenue requirements already adopted in various other proceedings, including its most recent phase 1 general rate case. This proceeding instead adopts various methodologies and processes for allocating the SCE's current and future revenue requirement between the various classes of customers and it provides calculations of SCE's marginal costs to be utilized in other rate proceedings until these rate setting tools are recalibrated in the next phase 2 proceeding. In very simple terms, this proceeding decides who pays how much and that this allocation is fair and reasonable.

This proceeding remains open to address the following proposals made by intervenors: (1) Real Time Pricing rate design proposals; and (2) the proposal to increase the rate differentials for Schedules TOU-D-4-9PM[1] and TOU-D-5-8PM in a separate decision.

# 1. Background

## 1.1. Procedural Background

Southern California Edison Company (SCE) filed its general rate case (GRC) Phase 2 application on October 23, 2020. The application proposed how to allocate SCE's costs amongst its customer classes and design rates to recover those costs, among other matters. Several parties filed protests and responses to SCE's application, including California Farm Bureau Federation (CFBF), California Choice Energy Authority, the Public Advocates Office of the California Public Utilities Commission (Cal Advocates), the Energy Producers

[1] TOU = Time of Use.

and Users Coalition, the California Large Energy Consumers Association (CLECA), the Solar Energy Industries Association (SEIA), Tesla, Inc., and The Utility Reform Network (TURN). SCE filed a reply to the protests and responses on December 10, 2020.

A prehearing conference was held on December 16, 2020, to discuss issues of law and fact, determine the need for hearing, set the schedule for resolving the matter, and to address other matters as necessary. A Scoping Memo was issued on January 20, 2021. On September 29, 2021, a Ruling granted a motion for an extension of time to serve rebuttal testimony and other changes to the schedule. On November 13, 2021, another Ruling was issued to extend time to allow for the submission of possible settlements of all issues other than Real Time Pricing (RTP) issues, and to suspend the scheduled dates for evidentiary hearings. On December 21, 2021, a Ruling Extending Rule 13.9 Deadline was issued to extend the deadline for a meet and confer on RTP related issues to, January 7, 2022. On February 14, 2022, a Ruling granted three motions to admit testimony into the record. Energy Toolbase Software, Inc. (Energy Toolbase) filed a motion for party status on February 28, 2022. A Ruling denied the untimely motion of Energy Toolbase for party status on March 3, 2022. Another motion to admit testimony into the record was granted on May 4, 2022. On February 14, 2022, a motion was granted to allow interested parties to serve limited supplemental RTP testimony and another motion was granted on February 16, 2022, to allow SCE to serve equally limited sur-rebuttal. Finally on April 6, 2022, a Ruling set two days of evidentiary hearings for RTP, which will be addressed in a subsequent decision and conclude this proceeding. Any other motions concerning the five uncontested settlements, not otherwise ruled on or addressed herein, are denied. Any motions pending on the litigated issues will be resolved in a separate ruling or a decision on the contested items.

## 2. Issues Before the Commission

The Scoping Memo identified the following issues:

1. Whether SCE's proposed marginal electric costs and cost of service calculations are reasonable and should be approved.
2. Whether SCE's proposed revenue allocation amongst its customer classes is reasonable and should be approved. This includes consideration of whether SCE's proposal for an allocation protocol to establish a going-forward process for categorizing and allocating authorized costs associated with or arising out of transportation electrification (TE) programs is reasonable and should be approved.
3. Whether SCE's proposed rate designs, including its demand charges, customer charges, dynamic rate options, and proposed time-of-use periods and seasons, are reasonable and should be approved.
4. Whether SCE's proposals with respect to residential rate design — including baselines, a separate Heat Pump Water Heater (HPWH) baseline, TOU-D-PRIME modifications, Conservation Incentive Adjustment recording modifications, and consolidation of submeter rates — are reasonable and should be approved.
5. Whether SCE's proposals with respect to non-residential rate design — including a direct current fast charger (DCFC) rate option, migration of certain Agricultural and Pumping (A&P) customers to new rate designs, elimination of support for certain Time Management Load Controller (TMLC) Devices, elimination of the Pay As You Grow special condition, a dimmable streetlight optional rate design, elimination of the Residential Walkway Lighting (DWL) tariff, elimination of the LS-2 Re-lamp option, and migration of customers on Santa Catalina

Island to time-of-use rates — are reasonable and should be approved.

6. Additionally, the Scoping Memo declined to establish a bifurcated track of this proceeding to consider ratemaking treatment of wildfire-related costs attributable to all of the large electrical corporations. Instead, the ratemaking treatment of SCE's fixed costs, including through fixed charges, was found to be within the scope of this proceeding. Parties were encouraged to serve testimony on SCE's costs that should be categorized as wildfire costs, the mechanism for allocating wildfire related costs to SCE's customer classes, and the appropriate ratemaking component to recover SCE's wildfire costs.

With the adoption of these five settlements the issues identified in the Scoping Memo are deemed to be satisfactorily resolved, except for the RTP issues and several other matters which will be addressed in a subsequent decision in this proceeding.

## 3. Settlements Generally

### 3.1. Standard of Review

Rule 12.1 of the Commission's Rules of Practice and Procedure (Rules) sets forth the Commission's requirements for parties to propose a settlement. In this proceeding the five separate sets of settling parties each separately complied with these requirements. The Commission may only adopt a settlement after determining whether or not the settlement complies with Rule 12.1.(d):

> The Commission will not approve settlements, whether contested or uncontested, unless the settlement is reasonable in light of the whole record, consistent with law, and in the public interest. The Commission may reject any proposed settlement for failure to disclose the information required pursuant to subsection (a) of this rule.

In this application, SCE bears the burden of proof to show that its requests are just and reasonable and any related ratemaking mechanisms are fair. In order for the Commission to approve any of the five proposed settlements the Commission must be convinced that the parties had a sound and thorough understanding of the application, and of all the underlying assumptions and data included in the record. This level of understanding of the application and development of an adequate record is necessary to meet our requirements for considering any settlement.

The record consists of all filed documents, the served testimony received into evidence, the five proposed settlements, and the five motions for their adoption. The five proposed settlements resolve almost all of the disputed issues in a balanced way which reflects a compromise of the positions as litigated by SCE and the other parties. These remaining issues will be addressed in a subsequent decision. We note that the settling parties, besides SCE and the Cal Advocates, represent a broad spectrum of ratepayer interests. Therefore, we find each one of the five proposed settlements to be reasonable in light of the whole record. There are no terms within any of the five proposed settlements that would or can bind the Commission in the future or that violate existing law. Therefore, we find the five proposed settlements consistent with the law. The settling parties addressed and resolved all issues as identified in the scoping memo, except for RTP and a couple of other issues, which will be addressed in a subsequent decision. As noted, the settling parties represent a broad spectrum of SCE's customers, and we may therefore conclude that the five proposed settlements are in the public interest.

#### 3.1.1. Conclusion

After reviewing the five uncontested proposed settlements we find that each proposed settlement, on its own merits and without consideration of the other proposed settlements, is reasonable in light of the whole record, consistent with the law, and in the public interest. It is clear from the record and from the five unique and separate settlement agreements that each settling group of interested parties for each proposed settlement had the necessary understanding of the issues and facts, and the capacity to engage in the settlement process. Therefore, it is reasonable to adopt all five proposed settlements.

## 4. Specific Settlements

### 4.1. The Marginal Cost and Revenue Allocation Settlement Agreement

The Settlement Agreement discussed in this section is the Marginal Cost and Revenue Allocation Settlement Agreement.[2]

The Settling Parties to this Settlement Agreement are: SCE; TURN; Cal Advocates; Small Business Utility Advocates (SBUA); CFBF; Agricultural Energy Consumers Association (AECA); California City-County Street Light Association (CALSLA); Federal Executive Agencies (FEA); California Manufacturers & Technology Association (CMTA); CLECA; Energy Producers and Users Coalition (EPUC); Energy Users Forum (EUF); and Direct Access Customer Coalition (DACC). These parties are further identified in the Settlement Agreement (Agreement at 1-3.)

The following parties take no position on the Settlement Agreement: SEIA; Enel X North America, Inc.; EVGo Services, LLC (EVGo); Tesla; Center for Accessible Technology (CforAT); California Choice Energy Authority; the California Solar & Storage Association; and the Western Manufactured Housing Communities Association (WMA).

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[2] Joint Motion of Southern California Edison Company and Settling Parties for Adoption of Marginal Cost and Revenue Allocation Settlement Agreement, December 13, 2021. Settlement Agreement is appended to the motion and is available at [430839609.PDF](430839609.PDF) (ca.gov).

The Settling Parties executed a Settlement Agreement[3] that resolves all issues concerning revenue allocation and applicable marginal costs in this proceeding. The Settling Parties note that:

> "Applicable marginal costs" refers to the adoption of marginal costs solely for the purpose of establishing a revenue allocation, and not for any other purposes. The Settlement Agreement does not reflect the general acceptance of any of the Parties marginal costs proposals. See Section III.A of the Settlement for more details. (December 17, 2021 Motion to Adopt Settlement Agreement at 2.)

To determine the revenue allocation for settlement purposes, the Settling Parties agreed to a set of marginal cost inputs that fell within the range of proposals made by the Settling Parties in their direct testimony, which were then moderated by agreed-upon "collaring" and "capping" parameters. Accordingly, at a high level, they assert that the resulting settlement "embodies a compromise and balance between the Commission's rate design principles of cost-causation and gradualism/rate stability."

Pursuant to the terms of the Settlement Agreement, and as soon as practicable following a Commission decision, but no earlier than June 1, 2022, SCE will adjust its rates for all its bundled service, Direct Access, Community Aggregator, and Community Choice Aggregation customers consistent with the terms of the Settlement Agreement.

Appendix A to the Settlement Agreement provides a matrix that summarizes the parties' litigation positions and the final settlement position, by issue. As detailed in the Settlement Agreement itself, the Settlement Parties resolved all issues raised in this proceeding with respect to revenue allocation

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[3] 430839609.PDF (ca.gov).

and applicable marginal costs. Among other things, the Settlement Agreement provides the means of establishing average rates by rate group and schedule when the settlement rate is first implemented and for the term of the Settlement Agreement.

#### 4.1.1. Generation Capacity Marginal Costs

As stated in the motion to the proposed settlement:

> [T]he Parties advocated for different values of marginal generation capacity. Ultimately, the Settling Parties compromised on a Generation Capacity Marginal Costs (GCMC) value at $100/kilowatt (kW) per year, for purposes of revenue allocation settlement. In addition, various parties initially had different proposals for allocating the proportion of MGCCs [sic][4] between 'peak'[5] and 'flex'[6] functions (as those terms are defined in the Settlement Agreement). Ultimately, the Parties agreed to use SCE's Capacity Allocation Tool to spread the GCMC across TOU periods and that it be partly allocated based on peak demand and partly based on the need for ramping capacity, *i.e.*, flexible capacity. (Motion at 8.)

This statement demonstrates that the parties began with differing positions which led them to an acceptable compromise and provides the necessary ratemaking data for the Commission to implement the settlement.

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[4] We assume that the parties intended to use the acronym GCMC and not MGCC; both refer to the marginal cost of generation capacity.

[5] "Peak," when used in the context of distribution design demand marginal cost components, refers to the portion of distribution marginal costs that are primarily sized to support the time-sensitive nature of coincident peak demand on the distribution system. "Peak," when used in the context of generation marginal cost components, refers to that portion of the marginal costs that is incurred to support the electric system during maximum system demand. (Settlement Agreement at 5.)

[6] Flexible Generation Capacity (*i.e.*, Flex) refers to the portion of generation capacity required to meet system ramping needs. (Settlement Agreement at 4.)

#### 4.1.2. Generation Marginal Energy Costs

As stated in the motion to the proposed Settlement Agreement:

> The Settling Parties advocated for different values of Generation Marginal Energy Costs (MECs). For the purposes of this revenue allocation settlement, the Parties agreed to a set of marginal energy costs that are based on an average forecasted total fuel cost of $5.65/MMBtu[7] ($1.42/MMBtu greenhouse gas-related costs based on the Cap-and-Trade Program and $4.23/MMBtu based on SoCal Citygate gas price) in addition to a Renewables Portfolio Standard adder forecast for the year 2024. (Motion at 8.)

This statement, as well as a review of the entire proposed settlement on this issue, demonstrates that the parties began with differing positions which led them to an acceptable compromise and provides the necessary ratemaking data for the Commission to implement the settlement.

#### 4.1.3. Customer Marginal Costs Methods

Various Parties advocated for different customer-specific marginal costs, based on different methodologies. As stated in the motion to the proposed settlement:

> For purposes of revenue allocation, the Settling Parties agreed on marginal customer costs that were determined based on a 50:50 ratio of SCE's Real Economic Carrying Charge (RECC) and TURN's New Customer Only marginal customer costs calculations. (Motion at 8.)

This statement, as well as a review of the entire proposed settlement on this issue, demonstrates that the parties began with differing positions which led

[7] 1 MMBtu is equal to 1 million British Thermal Units (BTU). Natural gas is measured in MMBtu's. 1 MMBtu = 28.263682 m3 of natural gas at defined temperature and pressure. One standard cubic foot of natural gas yields ≈ 1030 BTU (between 1010 BTU and 1070 BTU, depending on quality, when burned).

them to an acceptable compromise and the Settlement Agreement provides the necessary ratemaking data for the Commission to implement the settlement.

#### 4.1.4. Distribution Design Demand Marginal Costs

> The Parties advocated for different values of distribution design demand capacity. Ultimately, the Settling Parties agreed to adopt SCE's proposed Distribution Design Demand Marginal Cost (DDMC) value for the purposes of revenue allocation. SCE and interested parties have agreed to engage in discussions to explore derivation of design demand marginal cost and refinement to the peak/grid split for incorporation in SCE's next GRC Phase 2 proceeding. (Motion at 9.)

Effectively, parties accepted SCE's position for now and they will continue to examine this issue in the next proceeding. Such an outcome of one component is reasonable in a larger settlement and parties need not disclose why they reached this agreement or why any trade-offs in outcomes for different issues occur. We see no reason to consider modifying or rejecting this proposed settlement based on this outcome.

#### 4.1.5. Sales Forecast

The parties stated:

> The sales forecast embodied in the Settlement Agreement results from SCE's 2021 [Energy Resource Recovery Account] ERRA application (and supporting direct testimony therefrom), which represents SCE's then-current estimate of departing load for 2021. (Motion at 9.)

We see no reason to consider modifying or rejecting this proposed settlement based on this outcome and note that the Energy Resource Recovery Account (ERRA) Sales forecast is historically a fully litigated issue and that consistency in sales forecasts is desirable where feasible.

#### 4.1.6. Capping and Collaring

One unique feature added as a result of the settlement is the concept of "capping" and "collaring."[8] The motion states:

> SCE did not initially propose to "cap" or impose "collars" on any rate changes resulting from this proceeding. Various other parties proposed rate collars, however, at various percentage levels, and for different rates. Ultimately, the Settling Parties agreed to use collars of plus and minus 2.0 percent and 1.5 percent for delivery and generation services, respectively, for the purposes of revenue allocation. These percentages fall within the range of party proposals. This outcome promotes rate stability for customers. (Motion to at 9.)

We find that this mechanism is reasonable for use for the life of this decision. It does not mean that capping and collaring are the presumptive beginning policy position for SCE's subsequent GRC Phase 2 proceeding.

#### 4.1.7. Wildfire-Related Revenue Requirement

This portion of the proposed settlement is extremely detailed, and the parties entered into a very precise agreement on how to address many wildfire related proceedings and adopted rate recovery balancing and memorandum accounts.[9] The balances in these accounts can be very substantial amounts and therefore the cost recovery must be allocated across all customer classes as

[8] A cap is an upper limit, and a collar is a lower limit.

[9] As a matter of ratemaking practice, a balancing account is a cost recovery tool which records the actual costs of a well-defined project, activity, or event, authorized by the Commission, where the actual costs are uncertain, but prudently incurred costs are recoverable subject to a reasonable review. Often there is a revenue stream to partial fund these costs and the account tracks the difference between the revenues in rates and the actual costs incurred. Memorandum accounts are more subjective, where the costs for an activity may be reasonable but the scope and scale of the activity is not well defined or even certain to occur. Any memorandum account must be specifically authorized by the Commission and cost recovery is authorized in a subsequent proceeding after a finding that the company's behavior was prudent and the costs were reasonably incurred.

reasonably and as fairly as possible. Wildfire cost recovery was a specific component in the scope of the proceeding and this proposed settlement offers a reasonable resolution of the issues. As stated in the motion Settling Parties compromised on an allocation formula that would be applied to the following categories of existing and future Commission-authorized Wildfire-related Revenue Requirements (WRR). Settling Parties also compromised on an allocation formula that would be applied to the following categories of existing and future Commission-authorized WRR:

(1) Wildfire-related costs authorized in GRC base rates, including but not limited to, costs tracked in the following accounts: Wildfire Risk Mitigation Balancing Account; Vegetation Management Balancing Account; and Risk Management Balancing Account;

(2) Wildfire-related costs authorized in proceedings other than the GRC that review the reasonableness of the following accounts: Catastrophic Event Memorandum Account; Wildfire Expense Memorandum Account; Wildfire Mitigation Plan Memorandum Account; Fire Risk Mitigation Memorandum Account; and other Commission authorized balancing and memorandum accounts that may be established that include wildfire-related costs; and

(3) Wildfire-related costs that are authorized to be recovered through a Fixed Recovery Non-bypassable Charge.

(Motion at 10-11, omitting 9 separate and detailed footnotes.)

The Settling Parties agreed that the WRR would be recovered through distribution rates and the newly created allocation of the WRR would have two components:

- Capped Revenue Allocation: The revenues for up to the first $525 million (WRR Capped Amount) will be allocated using a 50 percent/50 percent average of the distribution allocator and System Average Percent (SAP) allocator, respectively; The annual WRR cap of $525 million will remain fixed until the next GRC Phase 2 is resolved; and

- Incremental Revenue Allocation: The WRR Incremental Revenue is all amounts of WRR that exceed the $525 million and will be allocated using a 12.5 percent/87.5 percent average of the distribution allocator and SAP allocator, respectively. (Motion at 11.)

This complex allocation continues with the development of a capped and an incremental revenue allocation that will be combined to develop a composite weighted average allocator (Special Allocator) that combines the distribution and SAP weights multiplied by the respective class allocators:

$$\text{SPECIAL ALLOCATOR}_i = (\text{DISTRIBUTION WEIGHT}*\text{DISTRIBUTION ALLOCATOR}_i) + (\text{SAP WEIGHT}*\text{SAP ALLOCATOR}_i)$$

There is a Special Allocator assigned to each rate class, using this formula where the subscript "i" in the formula represents each rate class.

The Motion summarizes the subsequent impact of the formula until the next Phase 2 GRC decision:

> Once the Special Allocator is established for each class, it will also be used to allocate any additional WRR authorized for rate recovery during the year until the next annual adjustment. The Special Allocator will be adjusted annually during the attrition years, concurrent with the annual sales forecast adjustment, to account for the then-current amount of the total annual WRR. The average distribution and SAP allocators will be updated annually to reflect changes to the billing determinants (sales), each class's percentage share of total system revenues, and the Distribution and SAP weights. These updates will be inputted using the formulas above to derive the Special Allocator that will be used during each year.

This brief and partial recital of the proposed settlement for wildfire related costs clearly shows that the parties worked in great detail to create a workable allocation methodology. Despite its details and its complexity, it is only a settlement, and therefore it is not binding beyond the effective life of this decision and it is not precedential, or even preferential, for SCE's next GRC Phase 2 proceeding, any other proceeding where the parties or the Commission reopen the question of wildfire cost allocation, or for any other jurisdictional electric utility.

#### 4.1.8. Transportation Electrification Allocation

The Settling Parties agreed that the allocation and recovery of revenue requirements associated with the four TE programs will continue to use the allocation and recovery methods ordered in each program's respective Commission decision: (i) Charge Ready Phase 1 Pilot; (ii) Charge Ready School and Parks; (iii) Charge Ready 2; and (iv) TE authorized in Decision (D.) 18-01-024 and D.18-05-040. They agreed that these allocations and recovery processes may change whenever the Commission modifies the underlying programs. This is a reasonable outcome for this issue, as a part of the overall settlement.

#### 4.1.9. Other Issues

The final major component of this settlement is that the parties will participate in a working group to

> discuss best practice and methodologies in the determination of DDMC for the purposes of revenue allocation and rate design. In particular, the working group will seek to understand cost factors such as load, installed capacity, distribution investment, and line miles used when defining design demand marginal costs, the peak/grid split, and the allocation of such costs to customer classes. (Motion at 13.)

This working group will focus on being prepared in time for SCE's probable 2025 GRC Phase 2 proceeding.

#### 4.1.10. Conclusion and Adoption of the Settlement

The above summary only provides highlights and does not detail the full contents of the settlement. The full settlement agreement and its attachments form the whole substance for its implementation, application to rates, and any subsequent interpretations.

We find this Marginal Cost and Revenue Allocation Settlement Agreement to be reasonable and in the public interest on its own merits and we adopt it herein without regard to the adoption or rejection of the other four separate settlement agreements which address separate and distinct components of the application.

### 4.2. The Residential and Small Commercial Rate Design Settlement Agreement

The second Settlement Agreement is the Residential and Small Commercial Rate Design Settlement Agreement[10] and is discussed in this section. The Settling Parties for this Settlement Agreement are: SCE, Cal Advocates, TURN, SEIA, CforAT, and WMA (for the residential rate design issues) and SCE, Cal Advocates, TURN, SBUA, and CFBF (for the small commercial issues).

The Settling Parties executed a Settlement Agreement that resolves all issues concerning residential and small commercial rate design issues in this proceeding. Appendix A to the proposed settlement also provides a matrix that summarizes the parties' litigation positions and the final settlement position, by issue. As detailed in the settlement agreement itself, the parties resolved all issues raised in this proceeding with respect to residential and small commercial

[10] Motion of Southern California Edison Company and Settling Parties for Adoption of of Residential and Small Commercial Rate Design Settlement Agreement, December 13, 2021. The Settlement Agreement is appended to the motion and is available at [432761053.PDF](432761053.PDF) (ca.gov).

rate design issues in this proceeding, except for: (1) RTP rate design proposals raised by Enel X North American, Inc. (Enel X), and Tesla, Inc. (collectively, the Joint Advanced Rate Parties (JARP))and SBUA; and (2) SEIA's proposal to increase the rate differentials for Schedules TOU-D-4-9PM[11] and TOU-D-5-8PM both of which will be resolved in the second track to this proceeding as already noted in this decision. The settling parties highlighted four areas of agreement in the motion for adoption, and the settlement agreement itself is well detailed and sufficient to support the motion.

First, the agreement includes SCE's proposed baseline usage allocation for Basic Service (as opposed to All-Electric) customers at the statutory maximum of 60 percent of average usage in each climate zone. It also includes SCE's All-Electric baseline usage allocation, which is currently set at 60 percent for the summer and 70 percent for the winter. These unopposed positions were actively supported by Cal Advocates. (Motion at 4.)

Second, SCE proposed to remove the eligibility restrictions and related attestation requirements for Schedule TOU-D-PRIME. SEIA supported this proposal whereas Cal Advocates and TURN opposed it. The Settling Parties then agreed to maintain the eligibility restrictions and attestation requirements for new customers voluntarily taking service on TOU-D-PRIME. In addition, SCE agreed to continue tracking the revenue differential associated with TOU-D-PRIME compared to TOU-D-4-9PM. (Motion at 4-5.)

Third, SCE proposed a rider option under TOU-D-PRIME for separately metered residential electric vehicle (EV) loads. Under this option, a monthly credit will be applied to the customer charge to make the separately metered

[11] Details of the current rate tariff offerings such as TOU-D-4-9PM and all other rates are found in SCE's Tariff Book. SCE Tariff Books | Regulatory Information | Home - SCE.

TOU-D-PRIME customer charge consistent with the separately metered Schedule TOU-EV-1 monthly meter charge. The reduced customer charge is intended to recover the cost of the additional meter, while recognizing that the service point and other associated facility costs are recovered through the customer charge of the primary meter. Cal Advocates supported this proposal, and it is included in the settlement. (Motion at 5.)

Fourth, based on a study required by the Residential and Small Commercial Rate Design Settlement Agreement in SCE's 2018 GRC Phase 2 proceeding, SCE proposed an incremental baseline allowance for customers with electric HPWH technology who take service on either TOU-D-4-9PM or TOU-D-5-8PM. Cal Advocates was the only party to respond to this proposal in testimony. Cal Advocates recommended that the Commission reject SCE's proposal as unnecessary. Settling Parties agreed that it would be appropriate to apply the anticipated incremental HPWH load allowance to the current baseline level. The Settling Parties further agreed that, to determine the anticipated incremental HPWH load for this analysis, it would be appropriate to account for a typical industry-prevalent unit with moderate-to-average efficiency and to calculate an appropriate incremental baseline allowance for each baseline zone by season. They then agreed on specific details of the allowances as contained in the details of the settlement. The Commission recently issued D.21-11-002 in the Building Decarbonization Rulemaking (Rulemaking 19-01-01). That decision ordered SCE and others to study net energy (electric and gas) bill impacts that result when a residential customer switches from a natural gas water heater to an electric HPWH. The settlement discusses this in detail and the settling parties assert that they considered the requirements in D.21-11-002 for HPWH rate adjustments and they believe that this settlement meets those requirements. (Motion at 7.)

Fifth, Cal Advocates and CforAT proposed that SCE adopt a line-item discount structure for non-tiered TOU rates to provide eligible customers with a medical baseline discount, an equivalent subsidy on the non-tiered TOU rates, even though those rates do not have a baseline credit structure. Under the Settlement Agreement, SCE agreed to provide a line-item discount of 11 percent to eligible customers selecting residential non-tiered rate schedules, including customers enrolled in the Self Generation Incentive Program, in order to provide these customers with an equivalent benefit to the medical baseline subsidy on rates that do not have a baseline credit structure. The discount will also be made available in conjunction with any newly developed non-tiered rate options. Customers selecting to receive the medical discount on a non-tiered rate would also receive all non-financial benefits provided to Medical Baseline customers. (Motion at 7.)

Sixth, SCE proposed updated submetering discounts for master-metered customers. Customers served on Schedule DMS-2 receive a discount for providing sub-metered service, which is comprised of a cost-of-service discount that is reduced by a Diversity Benefit Adjustment (DBA) and a multi-family Basic Charge adjustment. WMA, TURN and Cal Advocates proposed various adjustments to the proposal. Ultimately the parties agreed to a cost-of-service discount of 0.3032¢/day and a total discount of 0.2112¢/day, which were based on single-family costs except that the costs of the Final Line Transformer and Service Drop used were 67 percent of the full costs as determined by historical usage for the years 2018 through 2020. SCE also agreed to include the impact of the current, lower High Usage Charge (HUC) in the DBA component and to update the DBA if the HUC is subsequently eliminated for SCE. SCE agreed that, in its next GRC Phase 2 application, it would: (1) include a proposal to calculate and collect a DBA from customers served on Schedule DMS-3; and (2) use single-family underground costs as the starting point for calculating the sub-metering discount in that proceeding. (Motion at 8.)

Seventh and last, SCE agreed to withdraw a proposal to reduce the number of DMS rates by collapsing DMS-1 and DMS-3 into DMS-2.

#### 4.2.1. Conclusion and Adoption of the Settlement

The above summary only provides highlights and does not detail the full contents of the settlement. The full settlement agreement and its attachments form the whole substance for its implementation, application to rates, and any subsequent interpretations.

We find this Residential and Small Commercial Rate Design Settlement Agreement to be reasonable and in the public interest on its own merits and we adopt it herein without regard to the adoption or rejection of the other four separate settlement agreements which address separate and distinct components of the application.

### 4.3. The Streetlight and Traffic Control Rate Group Settlement Agreement

The third settlement agreement is the Streetlight and Traffic Control Rate Group Settlement Agreement[12] and is discussed in this section. The Settling Parties are SCE and CALSLA.

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[12] Joint Motion of Southern California Edison Company and California City County Street Light Association for Adoption of Streetlight and Traffic Control Rate Group Settlement Agreement, January 7, 2022. The Settlement Agreement is appended to the motion and is available at 439217187.PDF (ca.gov).

The Settling Parties filed a Settlement Agreement that resolves all issues for the streetlight and traffic control rate group. The Settlement Agreement contains the full terms and details of the negotiated outcome satisfactory to all active parties.

The parties resolved seven separate issues for the streetlight and traffic control rate group: (1) non-allocated revenues; (2) energy charges and customer charges; (3) Schedule DWL; (4) LS-1, Option E (LED[13] Conversion); (5) dimmable streetlights with network-controlled modules that are associated with smart sensors on LS-1 and LS-2 streetlights; (6) 90-Day Streetlight Stop Billing; and (7) Ancillary Device Rate Design.

#### 4.3.1. Non-Allocated Revenues

After considering both SCE's proposals and the other parties' counter proposals, the Settling Parties agreed to various trade-offs as described in the settlement. Additionally, as part of the separate Marginal Cost and Revenue Allocation Settlement Agreement (*see* Section 4.1 above) the non-allocated revenues would be set at a certain level initially (here, $77.870 million), and then defer to this Settlement Agreement to establish attrition year non-allocated revenues. Second, the Settling Parties agreed that, upon initial implementation, SCE would hold the non-allocated revenue requirement constant but increase by five percent the facilities charges in streetlight rate schedules that have facilities charges. SCE would collect the balance of non-allocated revenues via distribution energy charges. Third, in attrition years, the non-allocated revenues would be updated annually to account for, among other things, the sales transfer

[13] A light-emitting diode (LED) is a semiconductor light source that emits light when current flows through it. LEDs have many advantages over incandescent light sources, including lower power consumption, longer lifetime, improved physical robustness, smaller size, and faster switching.

of streetlights to eligible entities and LED conversions, and the facilities charges increase will be capped at five percent each year.

#### 4.3.2. Energy Charges and Customer Charges

The Settlement Agreement provides that SCE will set energy charges residually after non-energy charges are computed (including non-allocated revenues consistent with Section 4.1 above), and use marginal costs and usage characteristics to set the energy rates. SCE proposed to use the RECC methodology as the basis for setting the monthly charges for Schedules AL-2 and LS-3. For Schedule TC-1, SCE proposed to collect a maximum of 27 percent of allocated revenue via the customer charge. CALSLA agreed with SCE's proposal of AL-2 and LS-3 customer charges and the proposed treatment for Schedule TC-1 customer charges. The Settling Parties agreed to adopt SCE's proposal. (Settlement Agreement at 4-5.)

#### 4.3.3. Schedule Residential Walkway Lighting

SCE proposed to eliminate Schedule DWL and move existing customers to other applicable rate options. DWL is an un-metered rate that is currently closed to new customers, and serves walkway lighting for condominium complexes, homeowners associations, and apartment buildings. Settling Parties agreed to eliminate Schedule DWL. DWL currently has three rate options: Option A, Option B, and Option C. Due to the expected rate increase for DWL-A customers transitioning to Schedule OL-1, the rate impact will be phased-in over a 3-year period. For DWL-B and DWL-C, customers will be scheduled to transition off the rates (and migrated to Schedule LS-2-B) in 2022. (Motion at 5.)

#### 4.3.4. Streetlighting LED Conversion

SCE did not propose changes to the Option E LED Conversion program for LS-1 customers, but CALSLA proposed that Energy Efficient Premium

Charges for LS-1 Option E customers be eliminated because LEDs are the new standard lighting technology and high-pressure sodium vapor (HPSV)[14] lamps are obsolete. SCE includes incremental facilities charges only for LS-1 customers that participate in the LED conversion program, not for new installations of LEDs. SCE is required by law (Assembly Bill 719) to offer an LED conversion option and therefore will maintain incremental facilities charges for existing LED conversions. CALSLA proposed that SCE provide additional documentation to customers interested in switching to the LS-1 Option E that shows additional analysis and explains more details of the LED conversion. CALSLA provided an example conversion analysis template showing the LED wattage for each HPSV equivalent to help customers more easily understand the energy savings following conversion and better clarify energy rates used in calculations showing before and after conversion to LED. SCE agreed to adopt CALSLA's LED conversion presentation template. (Motion at 5-6.)

#### 4.3.5. Dimmable Streetlighting Pilot

SCE proposed pilot studies on the benefits and costs of dimmable streetlights with network-controlled modules that are associated with smart sensors on LS-1 and LS-2 streetlights. CALSLA supported the implementation of a dimmable streetlight pilot, but it believed SCE's LS-2 pilot proposal was too vague.

[14] A sodium-vapor lamp is a gas-discharge lamp that uses sodium in an excited state to produce light at a characteristic wavelength near 589 nanometers. Two varieties of such lamps exist: low pressure and high pressure. Low-pressure sodium vapor lamps are highly efficient electrical light sources, but their yellow light restricts applications to outdoor lighting, such as streetlamps. HPSV lamps emit a broader spectrum of light than the low-pressure lamps, but they still have poorer color rendering than other types of lamps.

Settling Parties agreed on a two-phase pilot open to existing LS-1 customers with smart sensors deployed and for LS-2 customers. Phase 1 will allow SCE to internally evaluate dimmable streetlight hardware and begin building standard interface/structure for customer billing. Phase 2 will allow SCE to test and refine interface for data integration, billing, and outage identification. Additionally, SCE will meet and confer with interested parties and conduct an audit and/or create a report evaluating the pilot's performance. (Motion at 6.)

#### 4.3.6. 90-Day Streetlight Stop Billing

SCE did not propose changes to its streetlight removal or stop-billing practices. CALSLA recommended that streetlight tariffs should be revised, and SCE remove streetlights within 90 days of a customer submitting a formal request and that any lamps not removed after 90 days will not be billed for service.

Settling Parties agreed that SCE shall conduct an assessment to determine which LS-1 removal requests are currently outside of a 90-day request window. For those customers currently outside the 90-day request window, SCE will stop billing the account of record and will ensure that removal of the streetlight in the field will occur in a timely manner. (Motion at 7.)

#### 4.3.7. Ancillary Device Rate Design

SCE proposed that ancillary devices attached to customer-owned streetlight poles should be placed on the Schedule Wireless Technology Rate (WTR), because unmetered wireless devices are similar to ancillary devices and automated billing functionality has already been built for WTR. CALSLA opposed SCE's proposal to bill low wattage ancillary devices attached to customer owned streetlights on the WTR and instead proposed that devices rated 35 watts or less should be billed the existing Wi-Fi rate. CALSLA did not oppose ancillary devices larger than 35 watts being billed the WTR rate.

Settling Parties agreed that ancillary devices will be put on WTR, however SCE will adjust billing components of the rate. First, SCE will expand lower energy usage tiers to accommodate low wattage ancillary devices. Second, SCE will exempt ancillary devices from paying the fixed monthly inspections charge. (Motion at 7.)

#### 4.3.8. Conclusion and Adoption of the Settlement

The above summary only provides highlights and does not detail the full contents of the settlement. The full settlement agreement and its attachments form the whole substance for its implementation, application to rates, and any subsequent interpretations.

We find this Streetlight and Traffic Control Rate Group Settlement Agreement to be reasonable and in the public interest on its own merits and we adopt it herein without regard to the adoption or rejection of the other four separate settlement agreements which address separate and distinct components of the application.

### 4.4. The Agricultural and Pumping Rate Group Rate Design Settlement Agreement

The fourth settlement agreement is the Agricultural and Pumping Rate Group Rate Design Settlement Agreement [15] and is discussed in this section. The Settling Parties are SCE, AECA, and CFBF.

[15] Motion of Southern California Edison Company, Agricultural Energy Consumers Association and California Farm Bureau Federation for Adoption of Agricultural and Pumping Rate Group Rate Design Settlement Agreement, January 11, 2022. The Settlement Agreement is appended to the motion and is available at 440092110.PDF (ca.gov).

The Settling Parties executed a Settlement Agreement that resolves all issues concerning A&P rate design issues in this proceeding. Appendix A to the proposed settlement also provides a matrix that summarizes the parties' litigation positions and the final settlement position, by issue. As detailed in the settlement agreement itself, the parties resolved all issues raised in this proceeding with respect to these rate issues.

#### 4.4.1. Common Rate Design Elements and Agricultural and Pumping Rate Options

As proposed in the details of the settlement agreement, rate structures for the A&P Rate Group will continue to generally consist of some combination of Customer Charges, TOU or seasonal Energy Charges, Time-Related Demand (TRD) Charges, and Facilities-Related Demand (FRD) Charges. There are illustrative Customer Charges, Energy Charges, TRD Charges, and FRD Charges in the Settlement Agreement. When the Settlement Agreement is first implemented, these illustrative charges will be adjusted as described in settlement.

A&P customers served at higher voltage delivery levels than the design voltage level for their rate class will continue to receive a voltage discount reflecting their lower cost of service. SCE will establish the discount levels based on the difference in marginal costs of service between the design or predominant voltage level for a given rate class and the higher voltage service options.

Finally, the determination of the power factor adjustment rates, which are designed to recover the costs of additional capacitors installed by SCE to improve power factor, will not be modified. (Motion at 5-6.)

#### 4.4.2. Time Management Load Controller Devices

The Settling Parties compromised on SCE's proposal to discontinue its support of Time Management Load Controller (TMLC) devices and to disable active TMLC devices from their corresponding meter. Instead of continuing support indefinitely as proposed by AECA and CFBF, the Settling Parties agreed that customers can keep their active TMLC devices until the implementation of the final decision for SCE's 2025 GRC Phase 2 Application or until the customer's TMLC device fails, whichever occurs first. This balances SCE's desire to phase out the TMLC devices with AECA and CFBF's desire to ease this transition for customers.

#### 4.4.3. Removal of Pay-As-You-Grow Special Condition

The removal of the pay-as-you-grow special condition as proposed by SCE was uncontested. It was therefore included in the settlement.

#### 4.4.4. Conclusion and Adoption of the Settlement

The above summary only provides highlights and does not detail the full contents of the settlement. The full settlement agreement and its attachments form the whole substance for its implementation, application to rates, and any subsequent interpretations.

We find this Agricultural and Pumping Rate Group Rate Design Settlement Agreement to be reasonable and in the public interest on its own merits and we adopt it herein without regard to the adoption or rejection of the other four separate settlement agreements which address separate and distinct components of the application.

### 4.5. Medium and Large Power Rate Group Rate Design Settlement Agreement

The fifth and final settlement agreement is the Medium and Large Power Rate Group Rate Design Settlement Agreement[16] and is discussed in this section. The Settling Parties are: SCE, FEA, CLECA, EUF, SEIA, EPUC, CMTA, DACC, EVgo, and Tesla.

The Settling Parties executed a Settlement Agreement that resolves all issues that have been raised with respect to default and optional rates for the Medium and Large Power (*i.e.*, Commercial & Industrial (C&I)) rate group customers except for (1) RTP rate design proposals raised by the JARP and SBUA; and (2) SEIA's proposal to implement an Option S storage rate with daily demand charges. These issues are excluded from the settlement and from this decision otherwise adopting the five partial settlements. They will be addressed in a separate decision after parties file briefs.

#### 4.5.1. Demand Charges

Demand Charges consist of TRD and FRD charges. TRD Charges may be differentiated by summer and winter seasons and by TOU periods. FRD charges are not differentiated by season or TOU periods. (Motion at 4.)

##### 4.5.1.1. Time Related Demand Charges

The Settlement Agreement's Option D (*i.e.*, the Base Rate) for each class will continue to collect most generation capacity costs via TRD Charges and continue to apply both in the summer on-peak period and also in the winter mid-peak period. The Settlement Agreement also continues to establish

[16] Motion of Southern California Edison Company and Settling Parties for Adoption of Medium and Large Power Rate Group Rate Design Settlement Agreement, February 18, 2022. The Settlement Agreement is appended to the motion and is available at [Microsoft Word - A2010012 Joint Motion For Adoption of Med and Lge Power Rate Design SA (CLEAN 2-12 vers).docx](Microsoft Word - A2010012 Joint Motion For Adoption of Med and Lge Power Rate Design SA (CLEAN 2-12 vers).docx) (ca.gov).

distribution TRD Charges in both the summer on-peak and winter mid-peak periods.

The Settlement Agreement's Option E (*i.e.*, the optional rate) offers a lower generation TRD Charge compared to Option D and has no distribution TRD Charge.

##### 4.5.1.2. Facilities Related Demand Charges

Both Option D and Option E in the Settlement (and the Standby rate options) include a non-coincident FRD Charge (also capacity reservation charge (CRC) Charges for Standby), which this Settlement Agreement maintains, to recover certain allocated delivery revenues, including SCE's base transmission revenues as adopted in Federal Energy Regulatory Commission proceedings, for the TOU-GS-2, TOU-GS-3, and TOU-8 rate classes.

#### 4.5.2. Base and Optional Rates and Rate Design (Non-Standby)

##### 4.5.2.1. Option D Base Rate — Eligibility Requirements and Rate Design

###### 4.5.2.1.1. TOU-GS-2 and TOU-GS-3

SCE's proposal to maintain the current eligibility that applies to Option D (*i.e.*, C&I customers with demands above 20 kW up to 500 kW) was unopposed and included in the settlement. (Motion at 4.)

CLECA opposed SCE's proposal to adopt a flat energy charge across all TOU periods to recover 95 percent of summer off-peak capacity cost and recommended that the energy charges be collected only during the summer TOU periods although the charge should be the same during each of the summer TOU periods. The Settlement Agreement reflects a compromise rate design as follows:

- Current TOU periods as adopted in D.18-07-006;
- A Customer Charge of $171.75/month (TOU-GS-2) and $505.50/month (TOU-GS-3);
- For distribution, a summer on-peak TRD Charge that recovers summer on-, mid- and five percent of off-peak capacity costs; a winter mid-peak TRD charge that recovers all winter peak capacity costs; TOU Energy Charges recover 95 percent of summer off-peak capacity costs across all TOU periods; and the use of an FRD Charge to recover grid-related costs; and
- For generation, summer on-peak costs are recovered via the Summer on-peak TRD and all winter capacity costs are recovered via winter mid-peak TRD Charges. Summer mid- and off-peak capacity costs are included in summer on- and mid-peak energy charges. Generation energy costs are recovered via volumetric TOU Energy Charges.

(Motion at 5-6.)

##### 4.5.2.1.2. Option D TOU-8 and TOU-8-PRI

SCE's proposal to maintain the current eligibility that applies to Option D (*i.e.*, C&I customers with demands over 500 kW but excluding certain large water pumping and agricultural customers) was unopposed and is included in the settlement. (Motion at 6.)

CLECA opposed some of Edison's proposals. The Settlement Agreement reflects a compromise rate design for TOU-8-Sec and TOU-8-Pri:

- Maintain the current TOU periods adopted in D.18-07-006;
- Customer Charge is as set forth in Appendix B of the Settlement Agreement;
- For distribution: (1) a summer on-peak TRD Charge that recovers summer on-, mid- and five percent of off-peak capacity costs; (2), a winter mid-peak TRD Charge that recovers all winter peak capacity costs; (3) TOU Energy Charges to recover 95 percent of summer off-peak capacity

costs across all TOU periods; and (4) the use of an FRD Charge to recover grid-related costs;

- For generation, the rate design consistent with the generation rate design for Option D of the TOU-GS-2 and TOU-GS-3 rate classes, as described above.

##### 4.5.2.2. Option E Optional Rate — Eligibility and Rate Design

###### 4.5.2.2.1. TOU-GS-2 and TOU-GS-3

The Settlement Agreement adopts SCE's unopposed proposal to maintain existing eligibility requirements, which includes no eligibility restrictions for TOU-GS-2 and TOU-GS-3 and exempts customers with Distributed Energy Resources (DER) technologies from Standby charges. (Motion at 8.)

CLECA proposed the development of Option E rates that use billing determinants for the Option E customer group and not on the entire customer class. It has concerns that there would otherwise be cost shifts to other customers and inadequate price signals to Option E customers.

The Settlement Agreement adopts SCE's rate design for Option E. In addition to the rate design structure described above, Settling Parties agree that an energy rate scalar shall be applied to the TOU-GS-3 Option E energy charge to capture some of the revenue responsibility shortfall associated with customers participating on Option E. The energy scalar is set to recover 25 percent of revenue responsibility shortfall within the TOU-GS-3 Option E customer group. The revenue responsibility shortfall is calculated by measuring the difference between the Equal Percent of Marginal Cost scaled marginal cost revenue responsibility and the revenue recovered from the non-scaled revenue of Option E customers at Option E rate. The energy scalar applied to TOU-GS-3 Option E will be TOU-shaped to preserve the TOU differential designed in the revenue neutral Option E. The scalar shall remain fixed during the attrition years once established during the implementation of the 2021 GRC Phase 2 Decision. Settling Parties also agree that the rebalancing of optional rate deficiency will no longer be performed in the attrition year rate adjustment for all rate groups as a result of this change, except for TOU-EV-8 and TOU-EV-9 as specified in Paragraph 4.E of the Settlement Agreement. In addition to the TOU-GS-3 energy rate scalar, Settling Parties agree that SCE shall perform a DER Class Working Group Study during the attrition year. (Motion 9-10.)

##### 4.5.2.2.2. Option E TOU-8

SCE proposed to maintain the existing eligibility requirements to Option E. No party addressed that proposal, and the Settlement Agreement adopts SCE's proposal to maintain the existing eligibility requirements, including the currently effective participation cap. (Motion at 10.)

CLECA proposed the development of a TOU-8-Option E rate that uses billing determinants for the Option E customer group and not on the entire customer class. CLECA asserted that doing otherwise would create an unfair cost shift from Option E customers to other customers. CLECA further asserted that if Option E rates are improperly set, the Option E customers will have an inadequate price signal directing them to shift load away from the on-peak periods. Furthermore, CLECA expressed concern that as the number of Option E customers grows, the cost shift to other customers will similarly grow.

Nevertheless, the Settlement Agreement adopts SCE's Option E rate design. As part of this Agreement, Settling Parties agree that SCE shall perform a DER class working group study during the attrition year. (Motion at 11-12.)

### 4.5.3. Attrition Year DER Class Study

Settling Parties agree that SCE, in consultation with a working group formed of representatives of Settling Parties, shall perform a study to explore the potential of creating a separate DER customer class. The study will review, but will not be limited to, concerns raised by parties regarding a potential cost-shift between high- and low-load factor customers under SCE's current optional rate design. One of the areas that the study will focus on is the determination of the cost to serve DER customers (or groups of DER customers if they are to be segregated by size or other characteristic), and other customers served on the electrification rates. The Settlement Agreement provides a detailed framework for the working group, and it will be conducted in the attrition years to inform SCE's 2025 GRC Phase 2 Application. (Motion 12-13.)

#### 4.5.4. Default Critical Peak Pricing Rate Design

The Settling Parties do not modify the currently effective Critical Peak Pricing (CPP) rates. The currently effective CPP rates reflect changes to CPP program adopted in D.18-07-006 and D.21-03-056. (Motion at 13.)

#### 4.5.5. Legacy Option B and Option R (Option A and Option B for Standby)

Medium and large customers with behind-the-meter solar generation facilities who meet the requirements of D.17-01-006 and D.17-10-018 will continue to be eligible for the Legacy rate options (A, B, or R) until the end of their legacy periods. As established in D.17-01-006 and D.17-10- 018, eligible solar customers may be served on legacy rates for ten years from their individual Permission to Operate dates, but not to exceed July 31, 2027 (non-public agencies) or December 31, 2027 (public agencies). No structural changes to the Legacy Options are adopted in the Settlement Agreement. (Motion at 14.)

#### 4.5.6. Standby Rate Design

Neither SCE nor any other party proposed structural changes for Standby rates. SCE did propose to incorporate the Option D rate design of TOU-8-S and

TOU-8-RTP-S. The Settlement Agreement adopts the following rate design for Large Power Standby customers: For TOU-8-S and TOU-8-RTP-S Standby customers, the rate designs will be aligned with the changes for the Option D rates as described in the settlement. SCE will continue to apply the Algorithm adopted in the 2015 GRC Phase 2 to determine Standby Demand and Supplemental Contract Capacity. An alternate TOU-8-S option for Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) Generating Accounts (*i.e.*, the replacement of the current Option TOU-8-S-A with TOU-8-S-LG) is also maintained.

Neither SCE nor any other party proposed structural changes for Medium Power Standby rates. SCE did propose to maintain the requirement for eligible customers to take service on the Option D rate of the underlying applicable tariff (except for RES-BCT customers).

The Settlement Agreement adopts the following rate design for Medium Power Standby customers: The Settlement Agreement provides those Standby customers whose demands are 500 kW or lower will be served on rate schedules within their applicable rate groups with rider charges for Standby service. The Standby CRC shall be the lesser of the FRD Charge that is based on the customer's otherwise applicable tariff or the Standby CRC specified for the TOU-8-S-Sec rate class. For standard Standby service, the underlying Base service will be taken on Option D. RES-BCT customers (*i.e.*, the Generating Account) with demands of 500 kW or lower will continue to be allowed to take Standby service on an underlying Option E rate. (Motion at 14-15.)

#### 4.5.7. EV Rate Design

Schedules TOU-EV-8 and TOU-EV-9 are separately metered rates applicable solely to the charging of EVs by customers. SCE proposed to extend the energy-only charges beyond the timeline established in D.18-05-040 until the implementation of the next GRC Phase 2 cycle or when rates consistent with the forthcoming Transportation Electrification Framework guidance can be implemented either as part of a Rate Design Window, or in a separate rate design proceeding as determined by the Commission, whichever occurs first. Additionally, SCE asserted that maintaining the energy-only structure provides stability to the developing DCFC industry. SCE also proposed to revise the energy charges to reflect updated marginal costs and revenue allocations. No party addressed SCE's proposal, and the Settlement Agreement adopted it. (Motion at 15.)

#### 4.5.8. RTP Rate Options

SCE proposed no structural changes to the existing forms of RTP rate options. JARP and SBUA submitted their own proposal. The Settlement Agreement provides that the RTP rate options shall continue to reflect the changes adopted in D.18-07-006. The Settlement Agreement does not address or resolve the RTP rate design proposals raised by JARP and SBUA. These proposals will be addressed in a separate decision in this proceeding. (Motion at 16.)

#### 4.5.9. Reliability Back-Up Service Rate Design (TOU-8-RBU)

The Settlement Agreement adopts SCE's uncontested proposal to retain the current treatment (*i.e.*, small Customer Charge, Generation TRD Charges and Energy Charges, with no distribution design demand recovery via TOU Energy or Demand Charges), with updates to reflect marginal-cost-based changes made to Option D (as discussed above). (Motion at 16.)

#### 4.5.10. Closing of Schedule GS-2 (Flat Rate)

The Settlement Agreement adopts SCE's uncontested proposal to close Schedule GS-2 after installing interval meters for a very small number of customers with demands of more than 20 kW but less than 200 kW who lack interval meters, particularly those on Catalina Island. SCE plans to replace the meters on Catalina with Edison SmartConnect meters in 2022 and migrate these customers to their applicable TOU-GS-2 rate schedule by 2024/2025. Therefore, the rate remains open for these customers pending SCE installing new meters. (Motion at 16.)

#### 4.5.11. Demand Response Credits (BIP and APS)

Rate structures and rate designs associated with SCE's demand response programs, e.g., Base Interruptible Program (BIP) and Automatic Power Shift (APS), shall reflect the respective incentive budgets at the current level as shown in Appendix B of the Settlement Agreement. BIP credits will continue to be provided based on the difference between the customer's summer and winter average on- and mid-peak demand and firm service level, where the average on- and mid-peak demands, in each season, are calculated by dividing the kilowatt hour usage in the period by the number of hours in the period. (Motion at 16-17.)

#### 4.5.12. Attrition Year Changes

As described in the Marginal Cost and Revenue Allocation Settlement Agreement (Section 5.1., above) when SCE's authorized revenues change in the future, SCE will first adjust rate levels for the default rate schedules (without CPP elements), e.g., Schedules TOU-GS-2-D, TOU-GS-3-D, and Schedule TOU-8-Sec-D, using a functional system average percentage change (SAPC) adjustment. SCE will then rebalance optional rate levels to ensure revenue neutrality between the default rate schedule and the optional rate schedules within each rate class. For example, generation revenue changes resulting from SCE's ERRA proceedings shall be allocated on a Functional SAPC basis, *i.e.*, the revised SCE generation revenue requirement will be allocated by applying a generation-level SAPC scalar to the relevant generation related charges, based on the difference between present rate revenues and proposed rate revenues for the default rate schedules. The optional rate schedules will then be adjusted to ensure revenue neutrality on a functional basis within each rate class.

#### 4.5.13. Conclusion and Adoption of the Settlement

The above summary only provides highlights and does not detail the full contents of the settlement. The full settlement agreement and its attachments form the whole substance for its implementation, application to rates, and any subsequent interpretations.

We find this Medium and Large Power Rate Group Rate Design Settlement Agreement to be reasonable and in the public interest on its own merits and we adopt it herein without regard to the adoption or rejection of the other four separate settlement agreements which address separate and distinct components of the application.

## 5. Environmental and Social Justice Action Plan

The Commission's Environmental and Social Justice (ESJ) Action Plan (Action Plan) serves as a roadmap for implementing its vision to advance equity in its programs and policies for ESJ Communities.

> The Action Plan will identify existing inequities and propose clear actions for how the CPUC can use its regulatory authority to address health and safety, consumer protection, program benefits, and enforcement to encompass all the

> industries it regulates, including energy, water, and communications programs. The CPUC will strive to develop strategies to address equity issues. The Action Plan will consider which steps the CPUC can take to engage directly with ESJ communities, build relationships, and gather information to understand the concerns of ESJ communities and how they want to engage with the CPUC.[17]

This proceeding determines the fair and reasonable methodologies to allocate SCE's revenue requirements and we adopt these settlements in the belief that the resulting ratemaking is not incompatible with the Action Plan. There was sufficient diversity of customer representation by the parties to this proceeding to ensure the outcome is consistent with the Commission's Environmental and Social Justice Action Plan.

## 6. California Environmental Quality Act

Rule 2.4[18] lays out the requirements for applications that are subject to the California Environmental Quality Act (CEQA). This application is exempt from CEQA under the ratemaking exemption.[19]

## 7. Safety

Nothing decided in this proceeding will have any impact on the safe and reliable operations of SCE's electric system.

## 8. Conclusion

This proceeding remains open to address (1) RTP rate design proposals raised by the JARP and SBUA; and (2) SEIA's proposal to increase the rate differentials for Schedules TOU-D-4-9PM and TOU-D-5-8PM. These matters will be resolved in a separate decision in this proceeding.

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[17] Microsoft Word - Env and Social Justice Action Plan_ 2019-02-21.docx (ca.gov) at 6.

[18] Rules-of-practice-and-procedure-may-2021.pdf (ca.gov).

[19] Public Resources Code Section 21080(b)(8). Law section (ca.gov).

## 9. Comments on Proposed Decision

The proposed decision of Administrative Law Judge Douglas M. Long in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3. Comments were filed on __________, and reply comments were filed on _____________ by ________________.

## 10. Assignment of Proceeding

Genevieve Shiroma is the assigned Commissioner and Douglas M. Long and Ehren Seybert are the assigned Administrative Law Judges in this proceeding.

## Findings of Fact

1. The record for the five uncontested proposed settlements is composed of the application, testimony and other exhibits of the parties, and all other filings including the settlement agreements themselves.
2. Edison and the parties developed a detailed evidentiary record which they used as a foundation for negotiating five separate partial settlements.
3. The parties to the five settlements adopted in this decision had a sound and thorough understanding of the issues, and of all of the underlying assumptions and data and they could therefore make informed decisions in each of the five instances of the settlement processes.
4. The array of parties to the settlements represents a broad range of SCE's customers and customer classes, and they were able to represent the overall best interests of all of SCE's customers.
5. No party has contested any one of the five settlements.

6. There was sufficient diversity of customer representation by the parties to this proceeding to ensure the outcome is consistent with the Commission's Environmental and Social Justice Action Plan.

7. There are no relevant safety related issues in this proceeding.

8. There are no relevant CEQA issues in this proceeding.

## Conclusions of Law

1. SCE alone bears the burden of proof to show that its requests are reasonable.

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

### The Marginal Cost and Revenue Allocation Settlement

3. The Marginal Cost and Revenue Allocation Settlement Agreement is not contrary to any law or previous Commission decision.

4. The Marginal Cost and Revenue Allocation Settlement Agreement is in the public interest as the agreement is a reasonable compromise between SCE and stakeholders that represent a broad range of interests.

5. The Marginal Cost and Revenue Allocation Settlement Agreement is not binding precedent in SCE's future Phase 2 GRC proceedings.

6. The Marginal Cost and Revenue Allocation Settlement Agreement and its attachments form the whole substance for its implementation, application to rates, and any subsequent interpretations.

### The Residential and Small Commercial Rate Design Settlement

7. The Residential and Small Commercial Rate Design Settlement Agreement is not contrary to any law or previous Commission decision.

8. The Residential and Small Commercial Rate Design Settlement Agreement is in the public interest as the agreement is a reasonable compromise between SCE and stakeholders that represent a broad range of interests.

9. The Residential and Small Commercial Rate Design Settlement Agreement is not binding precedent in SCE's future Phase 2 GRC proceedings.

10. The Residential and Small Commercial Rate Design Settlement Agreement and its attachments form the whole substance for its implementation, application to rates, and any subsequent interpretations.

**The Streetlight and Traffic Control Rate Group Settlement**

11. The Streetlight and Traffic Control Rate Group Settlement Agreement is not contrary to any law or previous Commission decision.

12. The Streetlight and Traffic Control Rate Group Settlement Agreement is in the public interest as the agreement is a reasonable compromise between SCE and stakeholders that represent a broad range of interests.

13. The Streetlight and Traffic Control Rate Group Settlement Agreement is not binding precedent in SCE's future Phase 2 GRC proceedings.

14. The Streetlight and Traffic Control Rate Group Settlement Agreement and its attachments form the whole substance for its implementation, application to rates, and any subsequent interpretations.

**The Agricultural and Pumping Rate Group Rate Design Settlement**

15. The Agricultural and Pumping Rate Group Rate Design Settlement Agreement is not contrary to any law or previous Commission decision.

16. The Agricultural and Pumping Rate Group Rate Design Settlement Agreement is in the public interest as the agreement is a reasonable compromise between SCE and stakeholders that represent a broad range of interests.

17. The Agricultural and Pumping Rate Group Rate Design Settlement Agreement is not binding precedent in SCE's future Phase 2 GRC proceedings.

18. The Agricultural and Pumping Rate Group Rate Design Settlement Agreement and its attachments form the whole substance for its implementation, application to rates, and any subsequent interpretations.

**The Medium and Large Power Rate Group Rate Design Settlement**

19. The Medium and Large Power Rate Group Rate Design Settlement Agreement is not contrary to any law or previous Commission decision.

20. The Medium and Large Power Rate Group Rate Design Settlement Agreement is in the public interest as the agreement is a reasonable compromise between SCE and stakeholders that represent a broad range of interests.

21. The Medium and Large Power Rate Group Rate Design Settlement Agreement is not binding precedent in SCE's future Phase 2 GRC proceedings.

22. The Medium and Large Power Rate Group Rate Design Settlement Agreement and its attachments form the whole substance for its implementation, application to rates, and any subsequent interpretations.

23. The adoption of these five settlement agreements is compatible with the Commission's Environmental and Social Justice Action Plan.

24. This application is exempt from CEQA under the ratemaking exemption.

25. This application has no safety implications or obligations.

26. Application 20-10-012 should remain open to address unresolved issues in a separate decision.

## O R D E R

**IT IS ORDERED** that:

1. Southern California Edison Company (SCE) must implement the terms of the Marginal Cost and Revenue Allocation Settlement Agreement as soon as

practicable after the issuance of this decision. Within 14 days of the effective date of this decision, SCE shall file a Tier 1 Advice Letter to submit the tariff modifications resulting from the rate design changes contained in the adopted settlement. These tariff modifications shall be effective today.

2. Southern California Edison Company (SCE) must implement the terms of the Residential and Small Commercial Rate Design Settlement Agreement as soon as practicable after the issuance of this decision. Within 14 days of the effective date of this decision, SCE shall file a Tier 1 Advice Letter to submit the tariff modifications resulting from the rate design changes contained in the adopted settlement. These tariff modifications shall be effective today.

3. Southern California Edison Company (SCE) must implement the terms of The Streetlight and Traffic Control Rate Group Settlement Agreement as soon as practicable after the issuance of this decision. Within 14 days of the effective date of this decision, SCE shall file a Tier 1 Advice Letter to submit the tariff modifications resulting from the rate design changes contained in the adopted settlement. These tariff modifications shall be effective today.

4. Southern California Edison Company (SCE) must implement the terms of The Agricultural and Pumping Rate Group Rate Design Settlement Agreement as soon as practicable after the issuance of this decision. Within 14 days of the effective date of this decision, SCE shall file a Tier 1 Advice Letter to submit the tariff modifications resulting from the rate design changes contained in the adopted settlement. These tariff modifications shall be effective today.

5. Southern California Edison Company (SCE) must implement the terms of The Medium and Large Power Rate Group Rate Design Settlement Agreement within 14 days of the effective date of this decision, SCE shall file a Tier 1 Advice Letter to submit the tariff modifications resulting from the rate design changes

contained in the adopted settlement. These tariff modifications shall be effective today.

6. Application 20-10-012 remains open to address: (1) Real Time Pricing rate design proposals; and (2) a proposal to increase the rate differentials for Schedules TOU-D-4-9PM[20] and TOU-D-5-8PM, which are not included in the five adopted settlement agreements.

This order is effective today.

Dated ____________________, at Sacramento, California.

[20] TOU = Time of Use.