ATTACHMENT 1 to EXHIBIT 1

California Public Utilities Commission Decision 16-03-030

"CPUC Phase 2 Order"

ALJ/SCR/avs **Date of Issuance 3/18/2016**

Decision 16-03-030 March 17, 2016

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) To Establish Marginal Costs, Allocate Revenues, Design Rates, and Implement Additional Dynamic Pricing Rates.	Application 14-06-014 (Filed June 20, 2014)

DECISION ADOPTING SETTLEMENTS ON MARGINAL COST, REVENUE ALLOCATION, AND RATE DESIGN

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DECISION ADOPTING SETTLEMENTS ON MARGINAL COST, REVENUE ALLOCATION, AND RATE DESIGN

Summary

This decision addresses the application of Southern California Edison Company (SCE) to establish marginal costs, allocate revenues, and design rates for service provided to its customers. The following uncontested settlement agreements are approved:

1. Marginal Cost and Revenue Allocation Settlement Agreement, as amended;
2. Residential and Small Commercial Rate Design Settlement Agreement;
3. Medium and Large Rate Group Rate Design Settlement Agreement;
4. Agricultural and Pumping Rate Group Rate Design Settlement Agreement; and
5. Street Light and Traffic Control Rate Group Settlement Agreement.

Unless otherwise provided in this decision, the revised rates will become effective no earlier than April 1, 2016 and will allow SCE to collect the revenue requirement determined in Phase 1 of its 2015 General Rate Case.

This proceeding is closed.

1. Procedural History

On June 20, 2014, SCE filed Application (A.) 14-06-014 to establish marginal costs, allocate revenues, and design rates for service provided to its customers in connection with its revenue requirements for service for 2015 - 2017.

This cost allocation and rate design proceeding is commonly referred to as "Phase 2" of a utility's General Rate Case (GRC).[1]

Protests to A.14-06-014 were timely filed by the Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), the California Farm Bureau Federation (CFBF)/Agricultural Energy Consumers Association (AECA) (jointly), and the Independent Energy Producers Association (IEPA). The Coalition for Affordable Street Lights (CASL) and the Alliance for Retail Energy Markets (AReM)/Direct Access Customer Coalition (DACC) (jointly) filed timely responses to SCE's application. SCE replied to these filings on August 4, 2014. A prehearing conference (PHC) was held on September 17, 2014 in order to establish the service list for the proceeding, discuss the scope of the proceeding, and develop a procedural timetable for the management of the proceeding.

The Assigned Commissioner and Administrative Law Judge's Scoping Memo and Ruling (Scoping Memo) was issued on September 26, 2014. The Scoping Memo confirmed the categorization of the proceeding and need for evidentiary hearings, defined the issues, established a schedule, and included time for parties to attempt to settle disputed issues. As is typical for GRC Phase 2 applications, the three general subjects of SCE's application are marginal costs, revenue allocation, and rate design. The Scoping Memo also reserved time for public participation hearings (PPHs) in locations to be determined. However, on July 2, 2015 the assigned Administrative Law Judge (ALJ) issued a ruling removing the PPHs from the proceeding schedule because several PPHs regarding residential rate design issues had recently been held in Rulemaking

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[1] SCE's Phase 1 GRC application, primarily addressing revenue requirements, was resolved by Decision (D.) 15-11-021 in A.13-11-003.

(R.) 12-06-013. For that reason, TURN and ORA did not oppose the recommendation of other parties that the Commission not hold PPHs in this proceeding. Although no PPHs were conducted in this proceeding, the Commission's Public Advisor has received a number of letters and electronic mail messages conveying the views of SCE's ratepayers on SCE's application. These messages are part of the proceeding record, and have been reviewed and considered by the assigned ALJ and members of the Commission.

The July 2, 2015 ALJ Ruling also scheduled a workshop for August 18, 2015. The purpose of the workshop was to provide an opportunity for SCE and other parties to present and discuss the methodology underlying the requests in SCE's application, as well as the positions and proposals of other intervenors.

ORA served its testimony on February 13, 2015. On March 13, 2015, the following parties submitted prepared testimony regarding some or all of the topics of marginal cost, revenue allocation and rate design: TURN, CFBF, AECA, Southern California Fluid Milk Handlers (SCFMH), Federal Executive Agencies (FEA), Energy Users Forum (EUF), California Manufacturers & Technology Association (CMTA), California Large Energy Consumers Association (CLECA), California City-County Street Light Association (CAL-SLA), Solar Energy Industries Association (SEIA), and DACC.

Following notice by SCE to all parties, an initial settlement conference took place on Thursday, March 26, 2015. Settlement discussions continued until the following five separate settlement agreements and supporting motions were filed with the Commission:

1. Marginal Cost and Revenue Allocation Settlement Agreement, filed August 14, 2015 by SCE, TURN, ORA, CFBF, AECA, SCFMH, FEA, CMTA, CLECA, EPUC, EUF, CAL-SLA, SEIA, DACC, and Energy Producers and Users Coalition (EPUC).[2]
2. Residential and Small Commercial Rate Design Settlement Agreement, filed October 7, 2015 by SCE, ORA, TURN, and the Western Manufactured Housing Communities Association (WMA).
3. Medium and Large Power Commercial Customer Rate Design Settlement Agreement, filed October 29, 2015 by SCE, FEA, CMTA, CLECA, EUF, SEIA, EPUC, ACWA, and IEPA.
4. Agricultural and Pumping Rate Group Rate Design Settlement Agreement, filed October 29, 2015 by SCE, AECA, CFBF, and SCFMH.
5. Street Light and Traffic Control Rate Group Settlement Agreement, filed October 6, 2015 by SCE CAL-SLA, CASL and the City of Yorba Linda.

[2] On September 9, 2015 SCE filed an amendment to the Marginal Cost and Revenue Allocation Settlement Agreement. The purpose of the amendment was to replace Appendix A of the Settlement Agreement with a "Revised Appendix A" that contains a new column showing "Current Treatment (i.e., 2012 GRC Settled Position)." The revised Appendix A also includes non-substantive edits and clarifying edits to the settled outcomes.

The settlement agreements listed above may be accessed at the Docket Card for this proceeding on the Commission's website, www.cpuc.ca.gov.

The settlements ultimately addressed all disputed issues. Evidentiary hearings were held on November 3, 2015 and November 19, 2015 to review the reasonableness of the settlement agreements. This proceeding was submitted for a decision by the Commission on December 4, 2015.

2. Standard of Review

The Commission has long favored the settlement of disputes. However, pursuant to Rule 12.1(d) of the Commission's Rules of Practice and Procedure, the Commission will not approve a settlement, whether contested or uncontested, unless it is found to be reasonable in light of the whole record, consistent with law, and in the public interest. Further, where a settlement agreement is contested, it will be subject to more scrutiny than an all-party settlement agreement. In this proceeding, none of the settlement agreements were ultimately contested.

As explained below, for each of the five settlement agreements, we find that the record supports a finding that the settlement agreements are reasonable, consistent with law, and in the public interest. SCE was represented by its staff and counsel in the proceeding. Parties representing all customer groups prepared and served exhibits on marginal costs, revenue allocation, and rate design issues. The record shows that the settlement agreements were reached after significant give-and-take between the parties, which occurred over a period of time. Together, these findings support our adoption of those agreements.

The Commission has also been aided in its decision by parties' informative and thorough presentations at the August 18, 2015 workshop facilitated by the Commission's Energy Division, and by the detailed comparison exhibits prepared by the parties to each of the five settlements in this proceeding.

First, the workshop included panelists from SCE, ORA, TURN, CLECA, and AECA, thus representing most of the customer groups affected by the outcome of this proceeding. The panelists provided an overview of the basic issues addressed by GRC Phase 2 proceedings and how rates are calculated, including objective explanations of the significant principals that underlie marginal cost and revenue allocation methodologies. The workshop also included discussion of "forward-looking" GRC Phase 2 issues such as changing load shapes in California; the changing nature of some customer classes, such as the Standby Class; possible means of better utilizing data gained through the utilities' automated metering infrastructure, and whether opportunities exist for greater integration with, and consistency between, these traditional regulatory rate design cases and other Commission proceedings that address matters such as distributed resource planning, long-term procurement, and demand response programs.

Second, the settlements themselves are the subject of Article 12 of the Commission's Rules of Practice and Procedure ("Settlements"). Uncontested settlements that address disputes over highly technical matters such as marginal costs, cost allocation and electric rate design can create some tension between the Commission's policy of encouraging such settlements and the concomitant requirement that the Commission affirmatively find that such settlements are, in fact, "reasonable, consistent with law, and in the public interest." Indeed, pursuant to Rule 12.6 of the Commission's Rules of Practice and Procedure, which addresses confidentiality of settlements, "no discussion, admission, concession or offer to settle, whether oral or written, made during any negotiation on a settlement shall be subject to discovery, or admissible in any evidentiary hearing" if a participant in that settlement objects to its admission. Nevertheless, hearings were conducted in this proceeding for the sole purpose of allowing the assigned ALJ to ask clarifying questions of the parties that entered into each settlement, and the settling parties worked collaboratively to testify on witness panels that enabled development of a detailed record on each settlement. This record provided additional information that supports our decision today, without causing settling parties to violate the spirit of Rule 12.6.

3. Interactions with Other Commission Proceedings

As explained in this section, in response to comments on the proposed decision in this proceeding we find it necessary to clarify the interaction between one element of several settlements and our expectations regarding the Commission's currently-open R.13-09-011, *Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements*. (.)

In D.14-12-024 in R.13-09-011, the Commission adopted a modified joint party proposal and set forth a series of actions toward 2018, the year of full implementation of "bifurcation" of demand response (DR) into load modifying and supply resources. On September 15, 2015, the Assigned Commissioner and ALJ in R.13-09-011 issued a "Ruling Providing Guidance for 2017 Demand Response Programs and Activities Proposal Filings" (September 15 Demand Response Ruling, or Ruling). The Ruling noted that the Commission will consider bridge funding for the 2017 demand response program year but, as required by D.14-12-024, proposals for bridge funding should include an increased effort toward bifurcation and toward more demand response being bid into the CAISO market. Finally, the Ruling determined that in order to move 2017 demand response programs beyond the current programs and closer to bifurcation and more integration into the CAISO market, the Commission should provide clear guidance to SCE, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) with respect to incrementally advancing the demand response portfolios toward those goals in 2017.

The Ruling directed SCE, PG&E and SDG&E to file proposals requesting Commission approval for 2017 demand response program and bridge funding authorization, in compliance with the guidance provided in the Ruling. Item 4 of that guidance directed that the utilities include in their 2017 proposals a "proposed schedule to consolidate all demand response programs and incentives into one demand response portfolio."[3] SCE filed its response to the Ruling on February 1, 2016, but declined to provide this proposed schedule, as directed by the Assigned Commissioner and ALJ.[4] SCE's refusal to provide the proposed schedule as directed in R.13-09-011 creates an uncertainty regarding whether SCE and the settling parties in the instant proceeding intend that the incentives adopted in this proceeding should "trump" values that may be adopted in R.13-09-011. To address this uncertainty, as suggested in comments on the proposed

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[3] September 15 Demand Response Ruling at 13.

[4] *See, "Southern California Edison Company's Proposal for Approval of its 2017 Demand Response Program and Bridge Funding Authorization"* at 39: "The Ruling indicated that the IOUs should include 'a proposed schedule to consolidate all demand response programs and incentives into one demand response portfolio.' SCE proposes that no consolidation occur for its DR portfolio at this time, as SCE's program funding requests and incentives are already considered in the appropriate proceedings."

decision, we clarify here that demand response program incentives for 2018 and beyond will be considered in R.13-09-011, or related/successor proceedings. New DR incentive levels from that proceeding should be implemented within thirty days of issuance of a Commission decision adopting them, notwithstanding the settled values included in the Settlements adopted in this Decision.

4. Settlement Agreements

3.1. Marginal Cost and Revenue Allocation Settlement Agreement

The Marginal Cost and Revenue Allocation Settlement Agreement resolves all issues related to marginal costs and revenue allocation in this proceeding. Its primary provisions are summarized in a comparison exhibit, Appendix A to the Settlement Agreement, which summarizes SCE's current tariff or policy, parties' original positions in their initial testimony related to marginal cost and revenue allocation issues, and the manner in which these issues have been resolved by the Settlement Agreement.[5] As noted above, the comparison exhibit provided in Appendix A served as the basis for testimony at evidentiary hearings where a panel of witnesses representing SCE, ORA, TURN, and CLECA/CMTA responded to questions from the assigned ALJ about the settlement.

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[5] The following parties take no position on the Agreement: the Center for Accessible Technology, the City of Lancaster, the Coalition for Affordable Street Lights, the City of Yorba Linda, the Western Manufactured Housing Communities Association (WMHCA), the Independent Energy Producers Association (IEPA), the Association of California Water Agencies (ACWA), and the Alliance for Retail Energy Markets (AReM).

Written testimony from SCE and the settling parties addressed the following major marginal cost and revenue allocation issues:

- Marginal customer, distribution demand, generation demand, and generation energy cost components;
- Allocation of functional distribution and generation unbundled revenue requirements based on marginal cost components or in accord with prior Commission decisions;
- Capping (or "collaring" as defined in the Settlement) of allocated revenues to rate groups to promote rate stability while achieving movement towards cost-based rate levels; and
- Changes to time-of-use (TOU) periods.

In addition to resolving all issues raised in this proceeding with respect to marginal costs and revenue allocation, the Settlement Agreement also provides the means of establishing average rates by rate group and schedule when this Agreement is first implemented and for the term of the Agreement.

We briefly summarize the major provisions of the Marginal Cost and Revenue Allocation Settlement Agreement in the following sections.[6]

3.1.1. Marginal Costs

Parties raised a number of issues regarding the calculation and methodologies used to derive marginal customer costs, marginal generation capacity costs, marginal energy costs, and marginal distribution demand costs. The Settling Parties were able to reach agreement on the allocation of SCE's total revenue requirement among the rate groups, thereby making moot the need to

[6] This summary relies extensively on the summary provided in the August 14, 2015 motion requesting adoption of the Marginal Cost and Revenue Allocation Settlement Agreement. Capitalized terms are defined in Paragraph 2 of the Settlement Agreement.

litigate and resolve the differences regarding proposed marginal cost methodologies and forecasts.

Thus, the Settlement Agreement does not reflect the approval of, or acceptance of, any of the Settling Parties' marginal cost proposals. However, the Settling Parties agree that the designated marginal costs set forth in Paragraphs 4.A. of the Settlement Agreement may be used for the purpose of initially establishing unit marginal costs that are used in SCE's revenue allocation and rate design model (SCE's Model).

3.1.2. Revenue Allocation

Several parties raised a number of issues regarding the allocation to rate groups of SCE's Commission-authorized distribution and generation revenue requirements. Parties disputed whether the Commission should cap or limit the amount of SCE's revenue requirement that is allocated to any rate group, and, if so, the level of the cap and whether separate caps should apply to distribution and generation revenue requirements. Some Settling Parties raised other issues with respect to how particular revenue requirements should be allocated among the rate groups, such as the costs for demand response and other public purpose programs.

In order to avoid further litigation and to mitigate potentially adverse impacts on any particular rate group based on directional movement towards cost-based rates in this proceeding, the Settling Parties agreed on how to allocate SCE's total revenue requirement on an overall revenue-neutral basis, to be effective after a Commission decision adopting this Settlement Agreement, based on a number of assumptions agreed upon by the Settling Parties. While no change to SCE's total system revenue requirement is requested in this proceeding, the Settling Parties agreed to establish a method to allocate revenues to each rate group based on agreed-upon marginal costs, methods of allocating revenues to each rate group, and a method for addressing future revenue requirement changes. The illustrative rates provided in Appendix B of the Settlement Agreement—which are based on an estimated consolidated revenue requirement—will be adjusted to reflect SCE's actual revenue requirements in accordance with the provisions of the Settlement Agreement when rates are first implemented.

The Settlement Agreement produces changes in average rates for bundled service and for direct access (DA) and Community Choice Aggregation (CCA) customer rate groups based on the estimated consolidated revenue requirement. To promote rate stability, the revenue allocations and illustrative average rates agreed to by the Settling Parties employ restrictions on delivery and generation revenue changes both above and below the functional system average percentage change (SAPC), as detailed in Table RA-6 and Paragraph 4.B.2 of the Settlement Agreement (i.e., "collaring").

In order to produce unbundled rates for rate design purposes and to provide a basis for other revenue requirement changes occurring after this proceeding and before SCE's next revenue allocation proceeding, the Settling Parties agree that SCE's authorized revenue requirements (i.e., the revenue requirements for transmission, distribution, SCE generation, Department of Water Resources (DWR) bond charge, DA cost responsibility surcharge, nuclear decommissioning, public purpose programs, etc.) shall be allocated to rate groups as specified in the Settlement Agreement in Paragraph 4.B.5, subparts a through i.

Finally, the Settling Parties agree that distribution and generation revenue requirement changes occurring after the Commission has issued a decision in this proceeding and until Phase 2 of SCE's next GRC proceeding is implemented shall be allocated pursuant to the functional character of the revenue requirement change on an SAPC basis, except to the extent otherwise specified in the Settlement Agreement with respect to CSI and SGIP revenue requirements, energy efficiency shareholder incentives, and demand response program revenue requirements as set forth in Paragraph 4.B.8, subparts b through d.

3.1.3. TOU Period and Default Critical Peak Pricing Issues

With respect to TOU periods, SCE acknowledged in its testimony that its currently effective TOU periods for default rate schedules, which have not changed in over thirty years, may be (or may soon become) out of date.[7] However, SCE proposed to revisit TOU period proposals in its 2018 GRC Phase 2 given that the transition to mandatory TOU happened only recently (in 2014 and 2015) for the roughly 600,000 non-residential service accounts not previously served on TOU rates whose peak demands are less than 200 kW. CLECA's testimony proposed changing TOU periods no later than SCE's 2015 rate design window (RDW) application in light of what it argued is an increasingly apparent load shape change owing to increased deployment of renewable generation resources, and argued that the current TOU periods send the wrong price signals.[8] CLECA's testimony stated that encouraging customers to increase load at 6 PM (under the current TOU periods) conflicts with and exacerbates the steep evening ramp-up caused by the changing net load shape. EUF's testimony urged SCE to revisit its TOU period definitions to account for the Net Demand for each

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[7] Exhibit SCE-2, Appendix D.

[8] Exhibit 304 at 13-14.

hour and within hours using the California Independent System Operator's definition of Net Demand.

With respect to SCE's default Critical Peak Pricing (CPP) proposal—to migrate eligible customers to default CPP in April 2017 at one time, instead of in three waves beginning January 1, 2016—three parties addressed this issue in their testimony. AECA supported it. CFBF also supported SCE's proposal, and requested a further delay to January/February 2018 to avoid transitioning Agricultural and Pumping customers during their harvest season.[9] ORA supported SCE's proposal while also proposing measurement, evaluation, outreach and reporting requirements.[10]

The Settling Parties recognize that migrating customers to default CPP in April 2017 and then, shortly thereafter, potentially changing the TOU periods (and possibly the CPP time periods) for default schedules, will be disruptive to customers and may lead to significant customer confusion and dissatisfaction.[11] Also, if there are changes to the TOU periods and CPP time periods, SCE will need to incur additional system costs as well as marketing, education and outreach costs following the April 2017 CPP default in order to implement these changes. For these reasons, the Settling Parties prefer that changes to TOU periods and CPP periods, if any, be implemented at the same time customers are migrated to default CPP (if they are not on CPP already): "bundling" these changes will allow for enhanced customer understanding and awareness of the

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[9] Exhibit 304 at 50-53.

[10] Exhibit ORA 101, Chapter 7, at 6-9.

[11] Currently, CPP events occur in four-hour windows from 2-6 PM during the summer on-peak period (12-6 PM) on TOU schedules.

rate changes, while at the same time eliminating costs and maximizing the operational efficiencies of SCE resources.

The Settlement Agreement resolves the TOU and related CPP issue by obligating SCE to file an RDW application no later than September 1, 2016, in which it will investigate and propose (as warranted) new default time-of-use periods (including updated CPP periods) for all customer classes.[12] The Settlement Agreement states that the new TOU periods shall reflect changes to the load curve net of Renewables Portfolio Standard (RPS) generation capacity output (the "net load curve"), and the RDW application will include a new study of the time-dependence, and, at SCE's option, the temperature-dependence, of its marginal subtransmission and distribution costs.[13]

According to Settling Parties, the Fall 2016 timing of the RDW is optimal because it will permit sufficient time for the Commission to issue a decision on SCE's application and for SCE to implement the TOU changes[14] and default CPP transition in 2018 subject to timelines and prerequisites that will be explained in the RDW application.

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[12] The TOU periods for SCE's new optional residential TOU schedule, TOU-D (adopted in D.14-12-048), will not be disturbed in the 2016 RDW. Rather, different TOU periods for residential rate schedules other than Schedule TOU-D may be examined and adopted in connection with the 2016 RDW, which will inform the showing SCE is required to make in its 2018 RDW ordered in D.15-07-001.

[13] This latter portion of the agreement, committing SCE to study time- and, at its option, temperature-dependence of its marginal subtransmission and distribution costs, acknowledges SEIA's proposal in its rate design testimony that SCE perform such a study by March 2016. Direct Testimony of SEIA at 21-22.

[14] Under the Settlement Agreement, the TOU period change will not result in modifications to the revenue allocations detailed in Paragraph 4.B. of the Settlement Agreement, which allocations are based on existing TOU periods.

3.1.4. Discussion

We find that the Marginal Cost and Revenue Allocation Settlement Agreement should be approved.

The record of this proceeding, consisting of prepared testimony, the settlement agreement and comparison exhibit, and further testimony by witnesses for SCE, ORA, TURN and CLECA/CMTA in hearings, supports a finding that the Marginal Cost and Revenue Allocation Settlement Agreement, as amended, fairly resolves the contested issues and is reasonable.

We also find that the Marginal Cost and Revenue Allocation Settlement Agreement, as amended, is consistent with law. The process followed by parties to achieve this settlement was in accordance with Article 12 of the Rules of Practice and Procedure. As explained by the Settling Parties, the settlement agreement represents a reasonable compromise of Settling Parties' respective litigation positions and is in the public interest because it avoids the cost of further litigation and conserves scarce resources of parties and the Commission. Finally, the agreed-upon revenue allocation moves revenue responsibility closer to the cost of service while moderating adverse bill impacts on customers.

3.2. Residential and Small Commercial Rate Design Settlement Agreement

The Residential and Small Commercial Rate Design Settlement Agreement resolves all issues raised in this proceeding with respect to residential and small commercial rate design. Its primary provisions are summarized in two comparison exhibits, Appendices A and D to the Settlement Agreement, which provide summaries of SCE's current tariff or policy, parties' original positions in their initial testimony, and the manner in which these issues have been resolved by the Settlement Agreement. Illustrative rates based on the Settlement Agreement are provided in Appendices B and E to the Settlement Agreement.

The comparison exhibits served as the basis for testimony at evidentiary hearings where a panel of witnesses representing SCE, ORA and TURN responded to questions from the assigned ALJ about the settlement.

As noted in the motion, this proceeding overlapped with two other proceedings whose outcomes had significant effects on SCE's residential rate design: A.14-01-015 (SCE's 2013 Rate Design Window) and Rulemaking (R.) 12-06-013, the Commission's *Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor-Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations* (RROIR). The Commission adopted a settlement resolving the contested issues in A.14-01-015 in D.14-12-048. The Commission issued a decision in Phase 1 of the RROIR (D.15-07-001) that adopted a road map for reform of the residential tiered rates through 2019. Among other things, the decision redefined and reduced the number of tiers in residential rates; left SCE's residential baseline percentage unchanged at 53%; adopted increased minimum charges for residential bills; and maintained SCE's average effective California Alternate Rates for Energy (CARE) discount of 32.5%.

We briefly summarize the major provisions of the Residential and Small Commercial Rate Design Settlement Agreement in the following sections.[15]

[15] This summary relies extensively on the summary provided in the October 7, 2015 motion requesting adoption of the Residential and Small Commercial Rate Design Settlement Agreement. Capitalized terms are defined in Paragraph 2 of the Settlement Agreement.

3.2.1. Residential Rate Design

For residential rate design, SCE put forth only three proposals that were not directly at issue in the RROIR or the 2013 RDW proceeding.

First, SCE sought separate baseline allowances by dwelling type (single-family versus multi-family dwellings) albeit only for its all-electric customers.[16] TURN and ORA each opposed the proposal, principally because of the large number of changes to residential rates that the Commission was already considering in the RROIR.[17] The Settlement Agreement declines to adopt a change to the status quo baseline allocation for all-electric customers. According to Settling Parties, SCE asserts that the baseline allocation issue (i.e., between single-family and multi-family all-electric customers) will be mitigated, in part, by the collapsing of residential tiers adopted in D.15-07-001, making the issue less pressing than it was from SCE's perspective at the time this application was filed.

Second, SCE sought to close Schedule TOU-D-T, the two-tiered, whole-house time-of-use (TOU) rate for residential customers. However, in the RDW proceeding, the Commission approved an unopposed settlement between SCE, SEIA, the Natural Resources Defense Council and ORA to keep Schedule TOU-D-T open until the rates implementing SCE's 2018 GRC Phase 2 become

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[16] All-electric customers, as distinct from Basic customers, are customers whose homes operate entirely by electricity instead of both electricity and gas.

[17] Exhibit 316 at 56-57; Exhibit ORA 101, at 6-3 to 6-9. EUF supported SCE's proposal (Exhibit 311 at 5-7). However, EUF does not appear to represent residential customers, and the all-electric baseline proposal was an *intra*-class revenue allocation issue. EUF represents "the interests of medium and large bundled service and Direct Access (DA) customers in California, primarily taking service on rate schedules for accounts with demand above 100 kW."

effective, notwithstanding any pending proposal to the contrary in this GRC Phase 2 proceeding.[18] Nothing in this Settlement Agreement disturbs any portion of the RDW Settlement Agreement, including this provision.

Third, SCE proposed updated diversity adjustments, submetering discounts and minimum average rates for master-metered customers on the assumption that its tiered rate proposal in the RROIR would be adopted. WMA did not serve testimony but intervened in this proceeding to ensure that its interests were protected with respect to these rates. Because the Commission did not adopt SCE's tiered rate proposal in the RROIR, the Settlement Agreement adopts updates to the diversity adjustment, submetering discount and minimum average rate consistent with the adjustments the Commission adopted to the tiered rates in the RROIR.

In sum, because most residential rate design issues were litigated and resolved in the RROIR and the 2013 RDW proceeding, there are fewer issues in this GRC Phase 2 than is normally the case; that small number of issues was resolved to the Settling Parties' satisfaction.

3.2.2. Small Commercial Rate Design

There were three main issues in this proceeding for small commercial rate design.

The first issue concerned the timing and program design for default critical peak pricing (CPP) for small and medium commercial customers. This matter was addressed and resolved in the Marginal Cost and Revenue Allocation (MC/RA) Settlement Agreement because of its close tie-in with the roll-out of

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[18] *See*, D.14-12-048, approving Paragraph 4.e.(iv) of the Settlement Agreement (Attachment A thereto).

updated TOU periods in the near future. In short, no party opposed SCE's alternate proposal, now included in the MC/RA Settlement Agreement, to implement default CPP for small commercial customers at one time in April 2017, instead of over two phases in January 2016 and January 2017. The MC/RA Settlement Agreement seeks to implement default CPP for small commercial customers concurrently with the implementation of new TOU periods, and the proposals for both will be set forth in the RDW application to be filed by SCE in the autumn of 2016.

The second issue concerned the level of the Customer Charge for small commercial customers. The Settling Parties agreed to adopt SCE's proposal to set the Customer Charge at $24, and then adjust it on a Functional System Average Percent Change (SAPC) basis thereafter. According to the Settling Parties, this approach will help maintain rate stability for these customers.

The third issue concerned how to address small commercial customers' eligibility for Schedule RES-BCT, an optional rate for local governments and campuses who own and operate an Eligible Renewable Generating Facility, as defined in the tariff, with a total effective generation capacity of not more than 5 MW.[19] Settling Parties explain that an unintended consequence of SCE's 2012 GRC Phase 2 was the removal of the Schedule RES-BCT option for small commercial standby customers. This Settlement Agreement restores small commercial customers to the position in which they stood before the 2012 GRC

[19] Schedule RES-BCT allows Local Governments or Campuses to generate energy from an Eligible Renewable Generating Facility for their own use (Generating Account) and to export energy not consumed at the time of generation by the Generating Account to SCE's grid. All generation exported to SCE's grid is converted into dollar credits and applied to the Benefiting Accounts designated by the Local Government or Campus.

Phase 2 because it creates an "Option C" exclusively for Schedule RES-BCT customers within the TOU-GS-1 rate class. No Settling Party disputed SCE's proposal.[20]

As outlined in further detail in the Settlement Agreement, the balance of small commercial rate design issues were resolved by updating rates to reflect the marginal costs adopted in the MC/RA Settlement Agreement, or by following status quo treatment of the setting of certain rate components.

3.2.3. Discussion

We find that the Residential and Small Commercial Rate Design Settlement Agreement should be approved.

The record of this proceeding, consisting of prepared testimony, the settlement agreement and comparison exhibits, and further testimony by witnesses for SCE, ORA and TURN in hearings, supports a finding that the Residential and Small Commercial Rate Design Settlement Agreement fairly resolves the contested issues and is reasonable.

We also find that the Residential and Small Commercial Rate Design Settlement Agreement is consistent with law. The process followed by parties to achieve this settlement was in accordance with Article 12 of the Rules of Practice and Procedure. As explained by the Settling Parties, the settlement agreement represents a reasonable compromise of Settling Parties' respective litigation positions and is in the public interest because it avoids the cost of further litigation and conserves scarce resources of parties and the Commission.

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[20] Two parties who are not signatories to this Settlement Agreement supported SCE's proposal: SEIA and ACWA, both of whom are signatories to the Medium and Large Power Rate Design Settlement Agreement, which addresses other issues related to Schedule RES-BCT.

3.3. Medium and Large Power Rate Group Rate Design Settlement Agreement

The Medium and Large Power Rate Group Rate Design Settlement Agreement resolves all issues in this proceeding related to rate design for this rate group, also known as the Commercial and Industrial (C&I) rate group. The Settlement Agreement's primary provisions are summarized below and in Appendix A to the Settlement Agreement, which summarizes SCE's current tariff or policy, parties' original positions in their initial testimony, and how each issue is resolved by the Settlement Agreement. Illustrative rates based on the Settlement Agreement are provided in Appendix B to the Settlement Agreement. The comparison exhibit served as the basis for testimony at evidentiary hearings where a panel of witnesses representing SCE, CLECA/CMTA and EPUC responded to questions from the assigned ALJ about the settlement.

The C&I rate group rate design issues addressed in testimony were the following:

- The appropriate levels of customer charges, Facilities Related Demand (FRD) charges, Time Related Demand (TRD) charges, and Time-of-Use (TOU) energy charges;
- The appropriate rate design for TOU periods and Critical Peak Pricing (CPP);
- The appropriate rate design for standby rates;
- Eligibility for standby customers wishing to take service on Schedule Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT); and
- The appropriate Demand Response (DR) program incentive levels.

We briefly summarize the major provisions of the Medium and Large Power Rate Group Rate Design Settlement Agreement in the following sections.[21]

3.3.1. Customer Charges and Demand Charges

SCE's testimony proposed that customer charges for all C&I rate groups be set based on the customer-related portion of distribution marginal costs, which includes customer service expenses and the cost of a final line transformer (FLT), service drop, and meter, and scaled to the full Equal Percentage of Marginal Cost (EPMC)-based level. The Settling Parties generally agreed with SCE's proposal. The Settlement Agreement sets customer charges at the full EPMC levels established in the MC/RA Settlement Agreement for all C&I rate groups.

With respect to demand charges, SCE's testimony proposed that FRD charges for all demand-metered C&I customers be a monthly $-per-kW charge, not differentiated by TOU period or season, based on SCE's proposed design demand marginal cost and scaled to the full EPMC-based level. CLECA/CMTA submitted testimony agreeing that FRD charges should be used to recover distribution capacity-related costs on a non-TOU basis.

The Settlement Agreement adopts SCE's position, but sets the FRD at the cost-based level established in the MC/RA Settlement Agreement.

SCE's testimony proposed that TRD charges for all demand-metered C&I customers be set as a monthly $-per-kW charge based on the "loss of load expectation" (LOLE)-weighted marginal cost of generation capacity, scaled to recover total allocated SCE generation revenues in combination with TOU

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21 This summary relies extensively on the summary provided in the October 29, 2015 motion requesting adoption of the Medium and Large Power Rate Group Rate Design Settlement Agreement. Capitalized terms are defined in Paragraph 2 of the Settlement Agreement.

energy charges. CLECA/CMTA submitted testimony that proposed to increase the summer on-peak charges and to decrease the summer mid-peak demand charges from current levels based on different marginal costs. CLECA/CMTA's testimony supported SCE's approach to include the summer off-peak capacity allocation in summer mid-peak demand charges. SEIA's testimony maintained that TOU energy rates in Options A and R rates are the appropriate way to recover generation-related, coincident-peak capacity costs from solar customers. EPUC's testimony recommended that TRD charges be set at EPUC's Generation Capacity Marginal Cost (GCMC) value of $199.48/kW-Year.

The Settlement Agreement sets TRD charges based on a capacity cost of $102 per kW-year for C&I customers with demands greater than 500 kW (i.e., TOU-8 rate groups), and $95 per kW-year for C&I customers with demands less than 500 kW (i.e., TOU-GS rate groups), with the revenue deficiency relative to the $108 per kW-year capacity cost value adopted in the MC/RA Settlement Agreement to be recovered through summer on-peak and mid-peak energy charges.

For all TOU-C&I rate schedules, SCE proposed that the TOU energy charges be based on SCE's proposed generation marginal energy costs (MECs). CLECA/CMTA submitted testimony proposing that for TOU-8-SUB and TOU-8-PRI, charges should be set based on CLECA's adjusted MECs, which are lower and differently-shaped than SCE's, in order to reflect lower gas costs and to maintain a significant cost-based differential between the on-/mid-/off-peak energy charges that would serve as an appropriate price signal to encourage the shift of load to off-peak periods. The Settlement Agreement sets TOU energy charges based on the MECs adopted in the MC/RA Settlement Agreement.

3.3.2. TOU Periods and Critical Peak Pricing

SCE submitted testimony proposing that the Commission should consider modifying TOU periods in the 2018 Phase 2 GRC, that default Critical Peak Pricing (CPP) be instituted in April 2017, and that the existing CPP rate structure, program design, and twelve-month customer bill protection provision be maintained. CLECA/CMTA submitted testimony maintaining that TOU periods should be revised no later than a 2015 rate design window based on forecasted changes in net load shapes. SEIA submitted testimony proposing that C&I customers on Option A and Option R rates be allowed to participate in CPP with a Capacity Reservation Level (CRL) designated at a value less than 0, and that CPP rates be designed to be revenue-neutral to Option A and Option R rates. EUF's testimony argued that SCE should revisit the definition of TOU periods no later than in its 2018 GRC Phase 2, and that the analysis should consider the Net Demand for each hour and intra-hour periods using the California Independent System Operator's (CAISO) definition of Net Demand.

Consistent with the MC/RA Settlement Agreement, this Settlement Agreement provides that SCE will propose TOU period adjustments in a September 2016 RDW Application. The Settlement Agreement also provides that default CPP migration be deferred to align with these potential TOU period redefinitions, and that the existing CPP rate structure, program design, 12-month bill protection provision, and the requirement that CPP CRL be designated as greater than or equal to zero be maintained.

3.3.3. Standby Rates

In recognition of the changing load profiles of certain types of generators who utilize SCE services for supplemental and back-up generation, SCE's testimony proposed that instead of the existing, largely manual determination of Standby customers' supplemental and back-up generation needs (billing determinants), a new algorithm based on recorded usage be used to determine the appropriate billing determinants. While generally supporting SCE's proposal, EPUC's testimony maintained that the process should be revised to include greater customer input about how the appropriate billing determinants are set. FEA agreed with EPUC. CLECA/CMTA tentatively supported SCE's algorithm with the modifications proposed by EPUC. SEIA supported SCE's proposal to phase in the proposed new methodology over several years. IEPA's testimony opposed SCE's proposed standby algorithm as proposed to be applied to merchant generators in the TOU-8 rate class, and maintained that SCE should be directed to develop a new standby tariff for such generators that reflects their potential unique costs of service.

The Settling Parties agreed to adopt the use of the algorithm to determine Standby customers' billing determinants, with the addition of an after-the-fact review process to ensure that the billing determinants were set with appropriate customer input regarding operating conditions for which the algorithm may not properly account, and a process to phase in the new algorithm-determined billing determinants for customers (to mitigate potentially high bill impacts).

3.3.4. Eligibility for Schedule RES-BCT

SCE submitted testimony proposing to permit Schedule RES-BCT customers with demands of less than 500 kW to again be eligible for Option A of their respective rate schedule, a rate option designed to recover all generation capacity costs through TOU energy charges, subject to the limits of SCE's share of the statewide RES-BCT cap. SEIA and ACWA supported SCE's proposal, but SEIA recommended that the rate treatment be similarly extended to RES-BCT customers with demands that exceed 500 kW (i.e., TOU-8 customers). The Settlement Agreement adopts SCE's proposal to permit RES-BCT customers with demands of less than 500 kW to take standby service on Option A of their respective rate schedule[22] (with Schedule S as a rider) and adopts SEIA's proposal to allow RES-BCT customers with demands that exceed 500 kW to take standby service on a new Schedule TOU-8-Standby Option A rate schedule. RES-BCT will be closed to all new customers when the statewide capacity cap of 250 MW is reached, or when SCE reaches 125 MW of eligible installed capacity, whichever occurs first.

3.3.5. Demand Response Program Incentives

SCE's testimony proposed that price- and reliability-based DR program incentives be set based on the proposed marginal generation capacity cost of $85/kW-year, but that the Summer Discount Plan (SDP) incentives not be updated, and instead be maintained at existing levels until a program redesign is proposed in SCE's 2017 DR Application. For customers who participate in both

[22] Pursuant to the terms of the Residential and Small Commercial Settlement Agreement, RES-BCT customers with demands less than 20 kW will take service on Option C of TOU-GS-1, not Option A.

the Base Interruptible Program (BIP) and the Demand Bidding Program (DBP), SCE's testimony proposed that their monthly BIP credit calculation exclude days on which the customer has participated in DBP by placing a bid. CLECA/CMTA supported SCE's proposal to exclude DBP as well as BIP event days when calculating the BIP incentive for to customers who are dual participating in both BIP and DBP, but recommended SCE use a $115.14/kW-year marginal generation capacity cost (i.e., a cost based on the full avoided cost of a combustion turbine), combined with the updated 2017 LOLE study, to develop BIP credit levels. EUF proposed that the SDP incentive be reduced.

The Settlement Agreement provides that the credits provided for non-firm service, including price- and reliability-based DR programs be determined based on the generation marginal capacity cost of $108/kW-year as agreed to in the MC/RA Settlement Agreement. However, the Settlement Agreement provides that BIP credit levels will be modified as follows: The level will be set at the average of the BIP incentive levels determined using the values adopted in the MC/RA Settlement Agreement and the current BIP incentive values adopted in D.13-03-031. The Settlement Agreement also adopts SCE's proposal to maintain SDP incentives at their existing levels.

Finally, the Settlement Agreement provides the means of establishing rates when this Agreement is first implemented and thereafter for the term of the Settlement Agreement.

3.3.6. Discussion

We find that Medium and Large Power Rate Group Rate Design Settlement Agreement should be approved.

The record of this proceeding, consisting of prepared testimony, the settlement agreement and comparison exhibit, and further testimony by witnesses for SCE, CLECA/CMTA and EPUC in hearings, supports a finding that the Medium and Large Power Rate Group Rate Design Settlement Agreement fairly resolves the contested issues and is reasonable.

We also find that the Medium and Large Power Rate Group Rate Design Settlement Agreement is consistent with law. The process followed by parties to achieve this settlement was in accordance with Article 12 of the Rules of Practice and Procedure. As explained by the Settling Parties, the settlement agreement represents a reasonable compromise of Settling Parties' respective litigation positions and is in the public interest because it avoids the cost of further litigation and conserves scarce resources of parties and the Commission.

3.4. Agricultural and Pumping Rate Group Rate Design Settlement Agreement

The parties to the Agricultural and Pumping Rate Group Rate Design Settlement Agreement reached an agreement that resolves all the issues raised in this proceeding with respect to rate design for these rate groups. The Settlement Agreement's primary provisions are summarized below and in Appendix A to the Settlement Agreement, which summarizes SCE's current tariff or policy, parties' original positions in their initial testimony, and how each issue is resolved by the Settlement Agreement. Illustrative rates based on the Settlement Agreement are provided in Appendix B to the Settlement Agreement. The comparison exhibit served as the basis for testimony at evidentiary hearings where a panel of witnesses representing SCE, AECA and SCFMH responded to questions from the assigned ALJ about the settlement.

The following Agricultural and Pumping (A&P) rate design issues were addressed in SCE's initial testimony and parties' opening testimony:

- The appropriate scope of SCE's Tariff Rule 1 definition of "Agricultural Power Service";

- The time and demand parameters of the Wind Machine Credit;
- The level of customer charges for A&P customers on Time-of-Use rates;
- The appropriate levels and parameters of Time-Related Demand charges and Facilities-Related Demand charges for A&P customers;
- The appropriate on-peak/off-peak differentials for Time-of-Use energy charges, and the appropriate level for super off-peak rates;
- The appropriate replacement for, or extension of, rate discounts for internal combustion engine (ICE) A&P customers to mitigate bill impacts from the expiration of the current ICE program;
- The appropriate implementation date for defaulting large A&P customers to Critical Peak Pricing ;
- The appropriate rate design treatment for revenue recovery from agricultural customers related to deviations in weather and resulting electricity usage;
- Whether it is appropriate to implement intra-class revenue shifts between small and large A&P rate groups;
- Self-certification for certain customers eligible for pumping service; and
- The appropriate level for demand response incentives under the AP-I (interruptible) program.

We briefly summarize the major provisions of the Agricultural and Pumping Rate Group Rate Design Settlement Agreement in the following sections.[23]

[23] This summary relies extensively on the summary provided in the October 29, 2015 motion requesting adoption of the Agricultural and Pumping Rate Group Rate Design

Footnote continued on next page

3.4.1. Definition of Agricultural Power Service

SCE's current Tariff Rule 1 does not define Agricultural Power Service to include fluid milk producers. SCE did not submit testimony on this issue, but in the 2012 GRC Phase 2, SCE agreed to modify its Rule 1 definition to include packers of whole fruits and vegetables (and associated cold storage), nut hulling and shelling operations, and cotton ginning. AECA and SCFMH submitted testimony proposing that the definition of Agricultural Power Service be further expanded to include fluid milk producers, whose product would not cross into what might be considered "processing" activities or "altering" a commodity in a fundamental way before it enters the market stream. The Settlement Agreement adopts the unopposed position of AECA and SCFMH, which treats fluid milk handlers consistently with the current Rule 1-defined eligible activities, Settling Parties agree this is a reasonable expansion of the definition of Agricultural Power Service and is consistent to how such customers are treated under PG&E tariffs.[24]

3.4.2. Wind Machine Credits

SCE's testimony proposed to continue to make Wind Machine Credits available to customers but to modify the credit to permit customers to incur no more than 1 kW of incidental usage during the on-peak period in the Summer Season. According to the Settling Parties, creating an incidental usage threshold will permit customers to test their wind machines in the summer. CFBF

Settlement Agreement. Capitalized terms are defined in Paragraph 2 of the Settlement Agreement.

[24] PG&E Electric Rule Number 1 Definitions, Qualifications for Agricultural Rates, Section B.1.(a).

supported SCE's position. The Settlement Agreement adopts the unopposed position of SCE and CFBF.

3.4.3. Customer Charges

SCE's testimony proposed that, with the exception of Schedules PA-1 and PA-2 (flat rates), customer charges for all TOU A&P rate schedules be set based on the Real Economic Carrying Charge (RECC)-based marginal cost method to recover the customer-related portion of distribution costs, which includes customer service expenses and the cost of a final line transformer (FLT), service drop, and meter, scaled to the full Equal Percentage of Marginal Cost (EPMC)-based level. CFBF's testimony proposed that all charges, including customer charges, be set at a level that is consistent with current tariffs, but adjusted by a single scaling factor to account for changes in the revenue allocated to the class. The Settlement Agreement adopts SCE's proposal with the following modifications: for TOU-PA-2 customers, FLT costs shall be recovered through non-TOU energy charges, and the customer charge shall be set to recover the remaining customer-related distribution costs; for TOU-PA-3 customers, the customer charge shall be set at a level to recover 50% of SCE's RECC-based customer-related distribution costs, and the balance of customer-related distribution costs shall be recovered through non-TOU energy charges. According to the Settling Parties, this treatment is consistent with the treatment of customer charges adopted in SCE's 2012 GRC Phase 2 Agricultural Settlement.

3.4.4. Facilities- and Time-Related Demand Charges

SCE's testimony proposed that facilities-related demand (FRD) charges for all demand-metered A&P rate schedules be established as a monthly $-per-kW charge, not differentiated by TOU period or season, and be set at the design demand marginal cost scaled to the full EPMC-based level. CFBF's testimony proposed that all charges, including FRD charges, be set at a level that is consistent with current tariffs but adjusted by a single scaling factor to account for changes in the revenue allocated to the class. AECA's testimony proposed that demand charges—both TRD and FRD—be applied on a daily basis, that FRD charges be differentiated by season, and that the total monthly demand charge be divided by the total days during the relevant season.

The Settlement Agreement adopts FRD charges that are set at the cost-based level established in the MC/RA Settlement Agreement scaled to the full EPMC level.

SCE's testimony proposed that TRD charges for all demand-metered agricultural and pumping rate schedules be set as a monthly $-per-kW charge based on the LOLE-weighted marginal cost of generation capacity, scaled to recover total allocated SCE generation revenues. CFBF's testimony proposed that all charges, including TRD charges, be set at a level consistent with current tariffs but adjusted by a single scaling factor to account for changes in the revenue allocated to the class. As indicated above, AECA's testimony proposed that both TRD and FRD charges be applied on a daily basis, and that the TRD be calculated in the following way: For the peak and part-peak charges, monthly TRD charges should be divided by the number of days with peak and part-peak hours during the relevant season.

The Settlement Agreement sets TRD charges based on a capacity cost of $85 per kW-year. The revenue shortfall relative to the $108 per kW-year value that is reflected in the MC/RA Settlement Agreement shall be recovered through the summer on- and mid-peak energy charges to maintain the same percentage of generation revenue recovery by TOU period.

For super off-peak (SOP) Schedules TOU PA-2 SOP and TOU PA-3 SOP, the Settling Parties agree that the capacity costs shall be based initially on the same $85 per kW-year marginal capacity cost but that the off–peak capacity be set at zero, with 50% of the revenue deficiency to be recovered through summer on-peak TRD charges and the remaining 50% to be recovered through energy rates.

3.4.5. TOU Energy Charges

For all TOU A&P rate schedules, SCE proposed that the TOU energy charges be based on SCE's proposed generation marginal energy costs, scaled to recover the authorized revenue requirement. CFBF recommended that, in order to avoid rate confusion for customers recently migrated to TOU rates, the TOU rate differentials for all TOU A&P rate schedules be maintained at the current levels. CFBF also recommended that SCE offer an optional tariff with reduced TOU differentials that are consistent with its marginal cost analysis. AECA maintained that marginal generation costs are primarily generation energy costs, and not generation capacity costs, and recommended that the TOU energy charges be set to reflect that understanding. The Settlement Agreement uses the MC/RA Settlement Agreement generation marginal energy cost levels, with an adjustment to account for the TRD revenue shortfall resulting from the $85/$108 per kW-year cap, to set TOU PA-2 and TOU PA-3 TOU energy charges.

For Schedules TOU PA-2 SOP and TOU PA-3 SOP, AECA submitted testimony that proposed that the TOU rates reflect how market prices are affected by the SOP-driven permanent load shift. AECA argued that the rate during the SOP period should reflect an "incentive" commensurate with the value that accrues to all customers as a result of this permanent load shift, and that conversely, the rate during the on-peak period should reflect a "penalty" commensurate with the cost that accrues to all customers if the load is shifted back into the on-peak period. CFBF argued that the rate differential between on-peak and super off-peak rates in the current SOP rate schedules should be maintained in order to maintain a strong incentive to shift loads away from the on-peak period.

The Settling Parties agree that SOP energy rates are to be set at the generation marginal energy cost, with the revenue deficiencies from reduced SOP energy charges recovered using the current TOU pricing ratios.

3.4.6. Agricultural and Pumping Interruptible (AP-I) Program

SCE's testimony proposed that AP-I incentive levels be calculated based on generation marginal capacity costs. No parties commented on this proposal in their prepared testimony. The Settling Parties agree that the AP-I incentive level will be determined based on the generation marginal capacity cost agreed to in the MC/RA Settlement Agreement with the following modification: the level will be set at 90% of the average of the AP-I incentive levels determined using the values adopted in the MC/RA Settlement Agreement and the current AP-I incentive levels adopted in D.13-03-031. This approach is largely consistent with the approach adopted for determining Base Interruptible Program (BIP) credits in the Medium and Large Power Rate Group Rate Design Settlement.

3.4.7. Agricultural ICE Rates

In D.05-06-016, the Commission adopted rate and line extension incentives for SCE's and PG&E's agricultural customers who use large diesel pumps to convert to electrical pumps. This rate schedule, known as TOU-PA-ICE (internal combustion engine conversion program), caps eligible customers' annual bill increases such that currently, ICE customers enjoy an approximate bill discount of 27% off of the bill they would otherwise pay if they were not on TOU-PA-ICE.

The schedule is set to sunset on December 31, 2015. CFBF submitted testimony maintaining that funding sources for a new cycle of the TOU-PA-ICE program should be explored. CFBF also argued that the ICE tariff expiration should be delayed at least until six months of customer education and outreach have been conducted. AECA submitted testimony proposing that the Commission should maintain TOU-PA-ICE rates at their current levels until a study is conducted on how to preserve the environmental benefits created by the program. AECA also argued that the Commission should order PG&E and SCE to consider reopening the pump engine conversion program, so as to facilitate achieving the California Air Resource Board's statewide goals in reducing local air pollution and greenhouse gas emissions.[25]

The Settling Parties acknowledge the public policy benefits of the TOU-PA-ICE program. For these reasons, and to promote rate stability, the Settling Parties agree that upon a Final Decision in this GRC Phase 2, a new rate discount structure, intended to phase-out the current Schedule TOU-PA-ICE discount, will be applied for the approximately 250 currently-eligible SCE ICE service accounts consistent with Paragraph 4.C.5 of the Settlement Agreement. The intent is to capture the approximate discount on the current TOU-PA-ICE schedule and increase customers' bills by a value of a third of the current percentage discount for two years (by one-third in 2016 and by two-thirds in 2017) until the customers are phased-out of the program by 2018.

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[25] On December 11, 2015 the Commission's Executive Director authorized SCE to extend the deadline to close Schedule TOU-PA-ICE by approximately six months, i.e. no later than June 30, 2016.

Phasing out the TOU-PA-ICE program does not impact or modify the terms of the MC/RA Settlement Agreement, nor does it modify the current method by which the TOU-PA-ICE discount is funded.

3.4.8. Implementation of Critical Peak Pricing

SCE submitted testimony requesting that one wave of default CPP migration take place, instead of the three contemplated by D.13-03-031. Specifically, SCE proposed April 2017 as the transition date for large agricultural customers.[26] CFBF submitted testimony proposing that the default CPP transition for these customers be deferred to January or February of 2018 to account for the harvest season. In the unopposed MC/RA Settlement Agreement, the Settling Parties agreed to implement default CPP concurrently with the implementation of the new TOU periods which may be adopted in connection with a Fall 2016 Rate Design Window application, including for large agricultural customers.

3.4.9. Revenue Recovery Related to Weather Deviations

AECA submitted testimony arguing that SCE should establish a balancing account to address revenue over-collections caused by variations in hydrological conditions (i.e., pumping customers use substantially more electricity during droughts). CFBF supported AECA's position, and submitted its own testimony maintaining that SCE should establish a balancing account to track the actual average rate impacts as compared to the contemplated rate impacts from GRC Phase 2 decisions. In the Settlement Agreement, SCE has agreed to participate in a PG&E-sponsored workshop on this issue.

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[26] The Commission has not mandated the transition of small and medium A&P customers to default CPP rates.

3.4.10. Intra-class Revenue Shifts Between Agricultural Rate Groups

SCE submitted testimony arguing that there should be no intra-class revenue shift between the TOU-PA-2 and TOU-PA-3 Rate Groups. CFBF submitted testimony maintaining that revenue allocation "caps" should be implemented separately for TOU-PA-2 and TOU-PA-3 Rate Groups, reflecting the distinct natures of the two customer groups. The Settlement Agreement does not adopt intra-class revenue shifts between these two Rates Groups, rendering moot Footnote 7 of the MC/RA Settlement Agreement that had obligated the Settling Parties, in the event that intra-class revenue allocation were adopted, to specifically identify the dollar amount of revenues allocated between the two rate groups using the same revenue requirement and load forecast assumptions as in the MC/RA Settlement Agreement.

3.4.11. Self-Certification for New Pumping Customers

SCE submitted testimony proposing that new customers seeking service under certain water pumping tariffs be required to sign a general water and sewerage pumping affidavit to verify that their electric usage meets the tariff requirements. SCE proposed using new Form 14-946 (Affidavit Regarding Eligibility for Pumping Service) to ensure that only self-certified eligible pumping customers receive service under the appropriate rate schedule. Large water agencies and agricultural customers would not be required to sign this affidavit. SCE's proposal was unopposed, and the Settlement Agreement adopts it.

3.4.12. Discussion

We find that the Agricultural and Pumping Rate Group Rate Design Settlement Agreement should be approved.

The record of this proceeding, consisting of prepared testimony, the settlement agreement and comparison exhibit, and further testimony by witnesses for SCE, AECA and SCFMH in hearings, supports a finding that the Agricultural and Pumping Rate Group Rate Design Settlement Agreement fairly resolves the contested issues and is reasonable.

We also find that the Agricultural and Pumping Rate Group Rate Design Settlement Agreement is consistent with law. The process followed by parties to achieve this settlement was in accordance with Article 12 of the Rules of Practice and Procedure. As explained by the Settling Parties, the settlement agreement represents a reasonable compromise of Settling Parties' respective litigation positions and is in the public interest because it avoids the cost of further litigation and conserves scarce resources of parties and the Commission.

3.5. Street Light and Traffic Control Rate Group Settlement Agreement

The parties to the Street Light and Traffic Control Rate Group Settlement Agreement reached an agreement on a settlement that resolves all issues related to non-allocated revenues assigned to the Streetlight Rate Group, streetlight and traffic control rate design issues and streetlight tariff matters. Appendix A to the Settlement Agreement summarizes SCE's current tariff or policy, the positions of the Parties in their prepared testimony and how each issue is resolved by the Settlement Agreement. Illustrative rates based on the Settlement Agreement are provided in Appendix B to the Settlement Agreement. Appendix C shows the proposed changes to Schedule LS-3 under the Settlement Agreement. The comparison exhibit served as the basis for testimony at evidentiary hearings where a panel of witnesses representing SCE, CASL, CAL-SLA and the City of Yorba Linda responded to questions from the assigned ALJ about the settlement.

We summarize the initial position of parties, and the settled outcomes, below. [27]

3.5.1. Non-Allocated Revenues

To determine the level of non-allocated revenues to be directly assigned to the Streetlight Rate Group to recover the costs of SCE-owned streetlight facilities such as lamps and streetlight poles, SCE proposed to retain the methodology agreed upon among settling parties and adopted by the Commission in the last GRC Phase 2, in D.13-03-031, which, based on the net book value and O&M expenses for streetlight service in 2012 as recorded in FERC account 373 and related O&M expense accounts, equaled $76.3 million.[28] SCE proposed to update that value upon implementation of the 2015 GRC Phase 2 rates using updated recorded data.[29] In recognition of the fact that several municipalities had expressed interest in converting SCE-owned LS-1 service to customer-owned LS-2 service, SCE proposed to perform a onetime adjustment to the non-allocated revenue requirement should such a transfer occur in the attrition years. SCE proposed that such an exception would be warranted to avert rate increases that would otherwise result from the conversion.[30]

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[27] This summary relies extensively on the summary provided in the October 6, 2015 motion requesting adoption of the Street Light and Traffic Control Rate Group Settlement Agreement. Capitalized terms are defined in Paragraph 2 of the Settlement Agreement.

[28] Exhibit SCE-4, at 84-85 (and Appendix J).

[29] Exhibit SCE-4, at 84, n. 72.

[30] *Id.*

CASL proposed in its direct testimony to cap non-allocated revenue requirement increases at 5 percent annually, and to record any excess spending in a balancing account to recover the costs from streetlight customers in years in which the embedded cost rises less than 5 percent.[31] CAL-SLA proposed to update SCE's non-allocated revenue requirement to $73.1 million to reflect the 2013 recorded net book value and the 2013 forecasted O&M. CASL also proposed an attrition year adjustment to reflect transfer of SCE-owned to customer-owned facilities should the sale of streetlights occur.[32] The City of Yorba Linda did not serve testimony about non-allocated revenues.

The Marginal Cost and Revenue Allocation (MC/RA) Settlement Agreement sets the non-allocated revenues at $73 million initially, and leaves to the Streetlight and Traffic Control Rate Design Settlement the setting of attrition year non-allocated revenues.[33] Under Paragraph 4.B. of this Settlement Agreement, the non-allocated revenues may go up or down by a maximum of 5 percent each Anniversary Year (as defined by the Settlement Agreement in Paragraph 2) depending on the cumulative number of Streetlight Lamp Counts and Streetlight Total Facilities Counts replaced relative to the Baseline Date of September 9, 2015. According to the Settling Parties, the "triggers" in Paragraph 4.B. of the Settlement Agreement balance the twin goals of accounting for changes in the non-allocated revenues assigned to the Streetlight Rate Group, on the one hand, while protecting against rate shock, on the other.

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[31] Exhibit 303 at 2-3.

[32] Exhibit 302 at 9.

[33] *See* Paragraph 4.B.3 at 16 of the MC/RA Settlement Agreement.

3.5.2. Rate Option for Distribution Pole-Mounted Streetlights

In the 2012 GRC Phase 2 Street Light and Traffic Control Rate Group Settlement Agreement, SCE committed to conducting "studies necessary to be able to propose in SCE's next Phase 2 GRC proceeding a rate option for lamps that are mounted on SCE's distribution poles as opposed to being mounted on poles that solely support streetlights."[34] In its testimony in this proceeding, SCE explained the results of these studies and concluded that the operational difficulties of implementing a new rate option for distribution pole-mounted streetlights outweighed the potential benefits.[35]

CASL recommended that the Commission require SCE to develop a rate option for distribution pole-mounted streetlights.[36] CAL-SLA opposed any new rate option, finding SCE's current rate adjustment for distribution poles to be adequate.[37] The Settlement Agreement commits SCE to proposing a distribution pole-mounted streetlight option in its 2018 GRC Phase 2.

3.5.6. Eligibility for Schedule LS-3

Schedule LS-3 ("Lighting-Street and Highway, Customer-Owned Installation-Metered Service") is a non-time-of-use rate schedule, and the Commission-approved tariff refers to streetlighting equipment "operated within the period from dusk to dawn." The City of Yorba Linda raised an issue in direct testimony regarding eligibility requirements for customers taking service on Schedule LS-3. Some City of Yorba Linda streetlight accounts were denied

[34] D.13-03-031, Attachment F at 9.

[35] Exhibit SCE-4 at 85-86 and Appendix H.

[36] Exhibit 303 at 6.

[37] Exhibit 302 at 2-3.at 14-15.

service under Schedule LS-3 because of their daytime and nonstreetlight purposes. The City of Yorba Linda argued that the language in the Applicability section of the tariff did not preclude customers with incidental non-lighting load, even incurred during the day, from taking service on the rate. The City of Yorba Linda pointed to other streetlight tariffs permitting incidental usage, and SCE's Rule 1 definition of "Street Lighting Service," which uses the word "primarily" to describe the usage for illumination of streets, alleys, highways or other public ways.

The Settlement Agreement resolves this issue by creating a TOU option in Schedule LS-3 – Option B – which will charge the same rates for daytime (on-peak) usage as customers on Schedule GS-1, and that specifically defines the amount of load that qualifies as "incidental" under that option. Option A will mirror the current structure of Schedule LS-3.

3.5.7. Customer Charges and Energy Charges

SCE proposed to update customer charges to reflect usage characteristics of the customers taking service on each streetlight and traffic control schedule. CASL proposed to equalize changes to facilities charges within the rate class across lamp types and wattages.[38] CAL-SLA's customer charge calculations differed from SCE's because CAL-SLA agreed with ORA's marginal customer cost methodology. The Settlement Agreement proposes to revise energy charges based on marginal costs adopted in the MC/RA Settlement Agreement.

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[38] CASL Direct Testimony, at 4-5.

With respect to energy charges, SCE proposed to update them to reflect usage characteristics of the customers taking service on each streetlight and traffic control schedule. CASL did not comment on energy charges. CAL-SLA proposed to allocate a greater portion of the revenues to energy rates and less revenue to facilities charges based on its revenue allocation proposal. The Settlement Agreement proposes to revise the energy charges based on the MC/RA Settlement Agreement.

3.5.8. Discussion

We find that the Street Light and Traffic Control Rate Group Settlement Agreement should be approved.

The record of this proceeding, consisting of prepared testimony, the settlement agreement and comparison exhibit, and further testimony by witnesses for SCE, CASL, CAL-SLA and the City of Yorba Linda in hearings, supports a finding that the Street Light and Traffic Control Rate Group Settlement Agreement fairly resolves the contested issues and is reasonable.

We also find that the Street Light and Traffic Control Rate Group Settlement Agreement is consistent with law. The process followed by parties to achieve this settlement was in accordance with Article 12 of the Rules of Practice and Procedure. As explained by the Settling Parties, the settlement agreement represents a reasonable compromise of Settling Parties' respective litigation positions and is in the public interest because it avoids the cost of further litigation and conserves scarce resources of parties and the Commission.

5. Conclusion

As discussed above, we find each of the five proposed settlement agreements in this proceeding to be reasonable in light of the whole record, consistent with law, and in the public interest. Accordingly, we shall grant the motions to adopt the following settlement agreements:

1. Marginal Cost and Revenue Allocation Settlement Agreement, filed August 14, 2015 by SCE, TURN, ORA, CFBF, AECA, SCFMH, FEA, CMTA, CLECA, EPUC, EUF, CAL-SLA, SEIA, and DACC.
2. Residential and Small Commercial Rate Design Settlement Agreement, filed October 7, 2015 by SCE, ORA, TURN, and WMA.
3. Medium and Large Power Rate Group Rate Design Settlement Agreement, filed October 29, 2015 by SCE, FEA, CMTA, CLECA, EUF, SEIA, EPUC, ACWA, and IEPA.
4. Agricultural and Pumping Rate Group Rate Design Settlement Agreement filed October 29, 2015 by SCE, AECA, CFBF, and SCFMH.
5. Street Light and Traffic Control Rate Group Settlement Agreement, filed October 6, 2015 by SCE, CAL-SLA, CASL, and the City of Yorba Linda.

To the extent any of these settlement agreements have closed or eliminated existing rate schedules, SCE shall work with the appropriate industry and/or consumer groups to ensure that the affected customers are notified of this occurrence and, as necessary, moved to an appropriate alternate rate schedule. The rates adopted in this decision shall be effective no earlier than April 1, 2016.

6. SCE's 2018 GRC Phase 2 Application

In comments on the proposed decision, SCE makes a procedural request that the Commission authorize SCE to file its 2018 GRC Phase 2 application on June 1, 2017. SCE notes that under the current Rate Case Plan, SCE's GRC

Phase 1 application is due on September 1, 2016, and thus SCE is required to file its GRC Phase 2 application on November 30, 2016.

SCE states that it has conferred with the parties in this proceeding, and no party opposes SCE's proposal.[39] SCE suggests that this schedule is reasonable given the anticipated June 1, 2016 date for implementing the rates adopted in the instant proceeding, "the desire by many settling parties to space out the timelines for litigating the other two investor-owned utilities' GRC Phase 2 proceedings," and the September 1, 2016 due date for SCE's rate design window application, which will propose new time-of-use periods (consistent with the Marginal Cost and Revenue Allocation Settlement Agreement approved in this Decision).

SCE also notes that it has committed to undertake various studies as part of the settlements approved in this Decision (e.g., separate distribution pole-mounted street light rates, assessment of certain station power loads, etc.) and a fifteen-month period between a final decision in one GRC Phase 2 and the beginning of another gives SCE sufficient time to perform such studies. Finally, SCE notes that its 2012 and 2015 GRC Phase 2 applications were also filed in the month of June, so extending the deadline would be consistent with the start date of the past two three-year cycles.[40]

SCE's request that the Commission authorize SCE to file its 2018 GRC Phase 2 application on June 1, 2017 is reasonable, and we adopt it in this Decision.

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[39] SCE states that parties understand that SCE would not "update" its application approximately four months after filing, as contemplated in the Rate Case Plan, and that this approach is consistent with the last two GRC Phase 2 cycles for SCE.

[40] SCE states that under its proposed schedule, it would expect to implement the 2018 GRC Phase 2 rates in the Fall of 2018.

7. Reduction of Comment Period

The proposed decision of ALJ Roscow in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code. Pursuant to Rule 14.6(c)(2) of the Commission's Rules of Practice and Procedure, all parties stipulated to a reduction of the 30-day comment period. Comments were filed on March 8, 2016 by SCE on behalf of itself and a subset of signatories to the Medium and Large Power Rate Design Settlement Agreement: CLECA, EPUC, EUF, CMTA and FEA (Joint Commenters). No reply comments were filed.

Pursuant to Rule 14.3 (c), comments shall focus on factual, legal or technical errors in the proposed decision and in citing such errors shall make specific references to the record or applicable law. Comments which fail to do so will be accorded no weight. Comments proposing specific changes to the proposed or alternate decision shall include supporting findings of fact and conclusions of law.

The Joint Comments request three modifications to the proposed decision (PD).

First, Joint Commenters request modifications to the section of the PD that addresses the incentive levels for the Base Interruptible Program (BIP) and the Automatic Powershift (APS) DR programs established in the Medium and Large Power Rate Group Rate Design Settlement Agreement. Joint Commenters correctly infer that the Commission intends to make clear in this decision that future DR program incentive levels, which we expect will be determined in a separate DR-specific proceeding, will override the incentive levels that are being adopted in this proceeding via the Medium and Large Power Rate Design Settlement Agreement (Joint Commenters also correctly note that other Settlement Agreements approved in the PD include provisions addressing DR incentive levels). Joint Commenters suggest that the Commission's intended outcome could be most clearly accomplished by modifying the PD to state that within thirty days after the issuance of a DR decision setting new incentive levels, the affected program tariffs should be revised accordingly notwithstanding the settlement values approved here. This is a reasonable suggestion that accomplishes the outcome intended in the PD. The PD has been modified accordingly, and to clarify the factual reasons that explain why the PD addressed this matter.

Second, Joint Commenters request an additional unrelated revision to the PD. Due to what they describe as a drafting error, Joint Commenters state that the Medium and Large Power Rate Design Settlement Agreement, as well as the accompanying comparison exhibit, inadvertently failed to indicate that the settling parties had agreed to adopt one of SCE's uncontested program design proposals for the Demand Bidding Program (DBP). This program feature is intended to modify the means of calculating incentives for customers participating in both BIP and DBP. Joint Commenters request that the PD be modified to add an Ordering Paragraph reflecting the parties' agreement. In support of their request, Joint Commenters note that in addition to the lack of opposition to SCE's proposal, CLECA and CMTA strongly supported it, and this support is included in the comparison exhibit. Furthermore, Joint Commenters note that SCE's witness accurately described the agreement during hearings. We have reviewed the record and the Settlement Agreement and find Joint Commenters' request to be both reasonable and supported by the record. We have modified the PD accordingly by adding an Ordering Paragraph reflecting the parties' agreement.

Third and finally, as noted immediately above, SCE makes a reasonable request for Commission authorization to file its 2018 GRC Phase 2 application on a date different from the date required in the Commission's Rate Case Plan. The PD has been modified to direct SCE to file that application on June 1, 2017.

8. Assignment of Proceeding

Michel P. Florio is the assigned Commissioner and Stephen C. Roscow is the assigned ALJ in this proceeding.

Findings of Fact

1. The Marginal Cost and Revenue Allocation Settlement Agreement, Residential and Small Commercial Rate Design Settlement Agreement, Medium and Large Power Rate Group Rate Design Settlement Agreement, Agricultural and Pumping Rate Group Rate Design Settlement Agreement, and Street Light and Traffic Control Rate Group Settlement Agreement are uncontested settlements.
2. The settlement agreements were entered into by parties representing all impacted customer groups.
3. The settlement agreements were reached after significant give and take between the parties.
4. Demand response program incentives for 2018 and beyond will likely be considered in R.13-09-011 or a related/successor ratesetting proceeding.

Conclusions of Law

1. The Marginal Cost and Revenue Allocation Settlement Agreement, Residential and Small Commercial Rate Design Settlement Agreement, Medium and Large Power Rate Group Rate Design Settlement Agreement, Agricultural and Pumping Rate Group Rate Design Settlement Agreement, and Street Light and Traffic Control Rate Group Settlement Agreement are each reasonable in light of the record, consistent with law, and in the public interest.

2. The Marginal Cost and Revenue Allocation Settlement Agreement, Residential and Small Commercial Rate Design Settlement Agreement, Medium and Large Power Rate Group Rate Design Settlement Agreement, Agricultural and Pumping Rate Group Rate Design Settlement Agreement, and Street Light and Traffic Control Rate Group Settlement Agreement, should each be approved.

3. Demand response (DR) program incentives for 2018 and beyond will be considered in R.13-09-011, or related/successor proceedings. New DR incentive levels from that proceeding should be implemented within thirty days of issuance of a Commission decision adopting them, notwithstanding the settled values adopted in this Decision.

4. Pub. Util. Code § 1822 and Commission Rule 10.3 concern discovery of computer models and databases by parties in a proceeding, but do not require these models and databases be made part of the evidentiary record.

5. Under the Rate Case Plan adopted in D.89-01-040, as modified in D.07-07-004 and D.14-12-025, SCE's 2018 GRC Phase 2 application would be due on November 30, 2016, with an SCE update due April 9, 2017.

6. SCE's request that the Commission authorize SCE to file its 2018 GRC Phase 2 application on June 1, 2017, with no provision for an update, is reasonable, and should be granted.

7. This order should be effective immediately so that SCE may prepare the necessary advice letters, parties may review and comment on the advice letters, and rates may be timely adjusted.

O R D E R

IT IS ORDERED that:

1. The motion dated August 14, 2015 which requests adoption of the Marginal Cost and Revenue Allocation Settlement Agreement is granted.

2. The motion dated October 7, 2015 which requests adoption of the Residential and Small Commercial Rate Design Settlement Agreement is granted.

3. The motion dated October 29, 2015 which requests adoption of the Medium and Large Power Rate Group Rate Design Settlement Agreement is granted.

4. Thirty days following the issuance of a final Commission decision in Rulemaking 13-09-011 or a related/successor proceeding that sets new demand response program incentive levels, Southern California Edison Company shall file a Tier 1 advice letter modifying the affected tariffs to reflect the new incentive levels.

5. The motion dated October 29, 2015 which requests adoption of the Agricultural and Pumping Rate Group Rate Design Settlement Agreement is granted.

6. The motion dated October 6, 2015 which requests adoption of the Street Light and Traffic Control Rate Group Settlement Agreement is granted.

7. Within 45 days of the date this order is mailed, Southern California Edison Company shall file an advice letter in compliance with General Order 96-B. The advice letter shall include revised tariff sheets to implement the revenue allocations and rate designs adopted in this order. The tariff sheets shall become

effective no earlier than April 1, 2016, subject to Energy Division determining that they are in compliance with this order. No additional customer notice need be provided pursuant to General Rule 4.2 of General Order 96-B for this advice letter filing.

8. Southern California Edison Company shall modify its tariffs to indicate that for customers participating in both the Base Interruptible Program (BIP) and the Demand Bidding Program (DBP), the monthly BIP credit calculation shall exclude days on which the customer has participated in DBP by placing a bid.

9. Southern California Edison Company shall file its 2018 General Rate Case Phase 2 application on June 1, 2017.

10. Application 14-06-014 is closed.

This order is effective today.

Dated March 17, 2016, at San Francisco, California.

MICHAEL PICKER
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
LIANE M. RANDOLPH
Commissioners