FILED
02/18/22
04:59 PM
A2010012

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	A.20-10-012 (Filed October 23, 2020)

MOTION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) AND SETTLING PARTIES FOR ADOPTION OF MEDIUM AND LARGE POWER RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

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Dated: **February 18, 2022**

Motion Of Southern California Edison Company (U 338-E) And Settling Parties For Adoption Of Medium And Large Power Rate Group Rate Design Settlement Agreement

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I.

INTRODUCTION

Pursuant to Rule 12.1 *et seq*. of the California Public Utilities Commission's (Commission's) Rules of Practice and Procedure, in Application (A.) 20-10-012, Application of Southern California Edison Company to Establish Marginal Costs, Allocate Revenues, and Design Rates, Southern California Edison Company (SCE), on behalf of itself and the other Settling Parties,[1] files this motion requesting that the Commission find reasonable and adopt the "Medium and Large Power Rate Group Rate Design Settlement Agreement" (Settlement Agreement), which is appended to this Motion as Attachment A.

The Settling Parties have 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 &

[1] The Settling Parties or Parties are SCE; Federal Executive Agencies (FEA); California Large Energy Consumers Association (CLECA); Energy Users Forum (EUF); Solar Energy Industries Association (SEIA); the Energy Producers and Users Coalition (EPUC); California Manufacturers & Technology Association (CMTA); Direct Access Customer Coalition (DACC); EVgo Services LLC; and Tesla, Inc. Pursuant to Rule 1.8(d), SCE has been authorized to file this motion on behalf of the Settling Parties.

Industrial (C&I)) rate group customers except for (1) Real Time Pricing rate design proposals raised by the Joint Advanced Rate Parties (JARP)[2] and Small Business Utility Advocates (SBUA), and (2) SEIA's proposal to implement an Option S storage rate with daily demand charges. Pursuant to the terms of the Settlement Agreement, and as soon as practicable following a Commission decision adopting the Settlement Agreement, but no earlier than June 1, 2022, SCE will adjust its rates for all of its medium and large power customers consistent with the terms of the Settlement Agreement.

Section II of this Motion provides the regulatory background related to this proceeding. Section III describes in general the positions advocated by the Parties and the terms of the Settlement Agreement. Section IV demonstrates that the Settlement Agreement is reasonable in light of the whole record, consistent with law, and in the public interest, and that it should be adopted without modification.

II.

REGULATORY BACKGROUND

A. Background of this Proceeding

This proceeding was initiated by the filing of SCE's application on October 23, 2020, A.20-10-012, along with service of SCE's prepared direct testimony regarding marginal costs, revenue allocation and rate design. On December 22, 2020, SCE served supplemental testimony regarding certain revenue allocation proposals. On January 20, 2021, the Assigned Commissioner and Assigned Administrative Law Judge issued a Scoping Memo and Ruling following a December 16, 2020 prehearing conference. The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) served its direct testimony on June 24, 2021 and then served amended testimony on July 8, 2021 and August 11, 2021. On July 26, 2021, the following Settling Parties submitted prepared testimony regarding medium

2 The JARP are California Solar and Storage Association, Enel X North America, Inc., and Tesla, Inc.

and/or large power rate design resolved by this Settlement Agreement: CLECA and EPUC.[3] Cal Advocates served supplemental testimony on revenue allocation on September 22, 2021.

The Settling Parties represent a broad spectrum of customer interests, as indicated in Paragraph 1 of the Settlement Agreement. Each Settling Party represents customers or groups of customers who are affected by, and have an interest in, the resolution of the Medium and Large Power rate group rate design issues that are addressed by this Settlement Agreement.

SCE provided notice to all parties of its intent to conduct a settlement conference related to all issues raised in the proceeding, and an initial settlement conference was held on August 12, 2021. Continuing discussions related to the potential settlement of issues in this proceeding occurred among the interested parties after the settlement conference.

III.

SUMMARY OF POSITIONS AND SETTLEMENT

As noted, the Settlement Agreement resolves all issues related to medium and large power rate design issues in this proceeding, except for (1) Real Time Pricing 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.[4] The Settlement Agreement's primary provisions are summarized below and in the comparison exhibit, Appendix A to the Settlement Agreement (Attachment A), which provides a comparison of party positions related to medium and large power rate design issues, and explains the manner in which these issues have been resolved by the Settlement Agreement.[5] Illustrative average rates for each rate class based on the Settlement Agreement are provided in Appendix B to the Settlement Agreement.

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[3] JARP and SBUA served testimony on Real-Time Pricing rate design proposals. SEIA served testimony proposing to implement an Option S rate. As stated above, these issues are not addressed or resolved by this Settlement Agreement. FEA, EUF, CMTA, DACC and EVgo did not serve testimony on medium and large commercial rate design issues. However, each of the Settling Parties actively participated in settlement discussions to ensure that their interests were protected with respect to issues pertaining to medium and large commercial rate design.

[4] These excluded issues are anticipated to be litigated and resolved by way of a final Commission decision.

[5] Capitalized terms are defined in Paragraph 2 of the Settlement Agreement. The comparison exhibit also includes uncontested issues.

A. Demand Charges (General Overview)

Demand Charges consist of Time-Related Demand (TRD) and Facilities-Related Demand (FRD) charges. TRD Charges may be differentiated by summer and winter seasons and by time-of-use (TOU) periods. FRD charges are not differentiated by season or TOU periods.

1. TRD 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 shall continue to apply both in the summer on-peak period and also in the winter mid-peak period.[6] Additionally, the Settlement Agreement continues to establish 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. More details are provided in the rate-specific discussions below.

2. FRD Charges

Both Options D and E (and the Standby rate options) include a non-coincident FRD Charge (also CRC Charges for Standby), which this Agreement maintains, to recover certain allocated delivery revenues, including SCE's base transmission revenues as adopted in FERC proceedings, for the TOU-GS-2, TOU-GS-3, and TOU-8 rate classes. More details are provided in the rate-specific discussions below.

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

1. Option D Base Rate – Eligibility Requirements and Rate Design

a) Option D Eligibility for TOU-GS-2 and TOU GS-3

SCE proposed to maintain the current eligibility that applies to Option D (*i.e.*, C&I customers with demands above 20 kW up to 500 kW). No party addressed that proposal and the Settlement Agreement adopts SCE's uncontested proposal.

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[6] TRD charges do not apply on weekends or holidays in the winter mid-peak period.

b) **<u>Option D Rate Design for TOU-GS-2 and TOU-GS-3</u>**

SCE proposed:

- Option D should continue to include a Customer Charge, adjusted to recover a portion of the final line transformer (FLT) costs in the grid distribution demand charge;
- Generation Energy should be recovered via TOU Energy Charges;
- Generation Capacity should be recovered through a combination of TOU Energy Charges and TRD Charges;
- For distribution, a summer on-peak TRD Charge that recovers summer on-peak, mid-peak and five percent (5%) of off-peak capacity cost; a winter mid-peak TRD charge that recovers all winter peak capacity cost; flat cent-per-kWh Energy Charges to recover ninety-five percent (95%) of summer off-peak capacity costs; and that Distribution Grid costs should be recovered through an FRD Charge.

CLECA opposed SCE's proposal to adopt a flat energy charge across all TOU periods to recover 95% 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.

Ultimately, the Settlement Agreement adopts a compromise rate design as follows:

- Current TOU periods 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 (5%) of off-peak capacity costs; a winter mid-peak TRD charge that recovers all winter peak capacity costs; TOU Energy Charges to

recover ninety-five percent (95%) of summer off-peak capacity costs across all TOU periods; and the use of an FRD Charge to recover Grid-related costs.

- 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.

c) **<u>Option D Eligibility for TOU-8</u>**

SCE proposed 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). No party addressed that issue and the Settlement Agreement adopts SCE's uncontested proposal.

d) **<u>Option D Rate Design</u>**

SCE Proposed:

(1) **<u>TOU-8-Sec and TOU-8-Pri</u>**

- Customer Charge established at full marginal-cost-based levels adjusted to recover a portion of the FLT costs in the grid distribution demand charge.
- Generation Energy should be recovered via TOU Energy Charges.
- Generation Capacity should be recovered through a combination of TOU Energy Charges and TRD Charges.
- For distribution, a summer on-peak TRD Charge that recovers summer on-, mid- and 5% of off-peak capacity cost; a winter mid-peak TRD charge that recovers all winter peak capacity cost; and flat cent-per-kWh Energy Charges to recover 95% of summer off-peak capacity costs.
- Distribution Grid costs recovered through an FRD Charge.

(2) Option D Rate Design for TOU-8-Sub

- Customer Charge established at full marginal-cost-based levels adjusted to recover a portion of the FLT costs in the grid distribution demand charge.
- Generation Energy should be recovered via TOU Energy Charges;
- Generation Capacity should be recovered through a combination of TOU Energy Charges and TRD Charges.
- For distribution, summer on-peak TRD Charge that recovers summer on-peak capacity cost; winter mid-peak TRD charge that recovers all winter mid-peak capacity cost.
- FRD Charge that recovers grid-related costs and summer mid- and off-peak and winter off- and SOP-peak capacity costs; no distribution costs recovered via Energy Charges.

Regarding TOU-8-Sec and TOU-8-Pri and TOU-8-Sub, CLECA opposed SCE's proposal to adopt a flat energy charge across all TOU periods to recover 95% 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.

Ultimately, the Settlement Agreement adopts a compromise rate design as follows for TOU-8-Sec and TOU-8-Pri:

- Maintain current TOU periods adopted in D.18-07-006.
- Customer Charge 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.

Option D incorporates the following rate design for TOU-8-Sub:

- Maintain current TOU periods adopted in D.18-07-006.
- Customer Charge as set forth in Appendix B to the Settlement Agreement.
- For distribution: (1) a summer on-peak TRD Charge that recovers summer on-peak capacity costs; (2) a winter mid-peak TRD charge that recovers all winter mid-peak capacity costs; and (3) an FRD Charge that recovers Grid-related costs and summer mid- and off-peak and winter off- and SOP-peak capacity costs (no distribution costs are recovered via Energy Charges).
- 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.

2. <u>Option E Optional Rate – Eligibility and Rate Design</u>

a) <u>Option E Eligibility for TOU-GS-2 and TOU-GS-3</u>

SCE proposed to maintain the existing eligibility requirements (*i.e.*, C&I customers with demands above 20kW and up to 500 kW) to Option E. No party addressed that proposal and the Settlement Agreement adopts SCE's proposal that to maintain existing eligibility requirements, which includes no eligibility restrictions for TOU-GS-2 and TOU-GS-3 and also exempts customers with DER technologies from Standby charges.

b) <u>Option E Rate Design for TOU-GS-2 and TOU-GS-3</u>

SCE proposed to offer an Option E that incorporates the following rate design:

- Option E should continue to include a Customer Charge, adjusted to recover a portion of the final line transformer (FLT) costs in the grid distribution demand charge.
- Generation Energy should be recovered via TOU Energy Charges.

- For generation, incorporate a TRD Charge set at 25% of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges.
  - For distribution, recover 60% of revenues (excluding the customer charge revenues) via TOU Energy Charges using SCE's as-proposed PLRFs, 30% via an FRD Charge and 10% via flat Energy Charges.

CLECA proposed the development of an Option E rates 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.

Ultimately, 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 twenty-five percent (25%) 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 EPMC 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 (described in Section III.D, below). 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 as described in Paragraph III.B.3, below

c) **Option E Eligibility for 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.

- Option E eligibility is limited to customers who:
    - Participate in PLS (eligible systems must account for at least 15 percent of the customer's annual peak demand, as recorded over the previous 12 months), cold ironing pollution mitigation programs or the charging of eligible ZEVs intended for the transport of people or goods.
    - Install, own, or operate solar, wind, fuel cells or other eligible onsite Renewable Distributed Generation Technologies as defined by CSI or SGIP, including paired storage systems. An eligible customer's system must have a net renewable generating capacity equal to or greater than 15 percent of the customer's annual peak demand, as recorded over the previous 12 months.
    - Install standalone storage. An eligible customer's system must have a minimum discharge capacity equal to or greater than 20 percent of the customer's annual peak demand, as recorded over the previous 12 months.
- Eligibility for Option E is further limited to customers with annual peak demands not exceeding 5 MWs.
- Customers receiving service on Option E are exempt from being required to take service on a Standby rate schedule.
- A 250 MW participation cap is maintained for customers with DER technologies. The capacity of new and existing customers who are utilizing PLS, cold-ironing, eligible ZEVs technologies will not be counted against the cap.

- For DERs, the qualifying capacity counted towards the 250 MW participation cap is based on the system's AC nameplate rating.
- For standalone storage, the qualifying capacity counted towards the cap is the discharge capacity of the storage system.
- For paired storage systems, the qualifying capacity counted towards the cap is the larger of the system's AC nameplate solar capacity or the discharge capacity of the discharge storage system (but not both).
- SCE agrees to file information-only ALs to report on the progress towards the cap. The frequency of such ALs will be one for every 50 MW of allocated capacity (based on the date of the signed interconnection agreement for the DER) until 200 MW is reached, at which time SCE will file monthly ALs until the cap is reached. The monthly ALs will include additional data to help inform actual progress towards the cap, *e.g.,* such as how long systems have been allocated capacity under the 250 MW cap but have not yet received permission to operate (PTO).

d) <u>Option E Rate Design for TOU-8</u>

SCE proposed to establish an Option E for TOU-8-Sec and TOU-8-Pri with rate design that is identical to the rate design described above for TOU-GS-2 and TOU-GS-3 Option E.

SCE's proposal for Option E for TOU-8-Sub incorporates the following rate design:

- Current TOU periods adopted in D.18-07-006.
- A Customer Charge established at full marginal-cost-based levels adjusted to recover a portion of the FLT costs in the grid distribution demand charge.
- For distribution, an FRD Charge is used to recover Grid-related costs with the remaining revenue recovered via TOU Energy Charges using SCE's as-proposed PLRFs
- For generation, recovery of energy and capacity revenues is via a TRD Charge set at twenty-five percent (25%) of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges.

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.[7] 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.

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 as described in Paragraph III.B.3 below.

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.[8] In the study, SCE will examine possible class definition for DER customers and perform marginal cost-based allocation and rate setting for the resulting group. The study will determine which types of customers, or services, should be categorized in a potential DER class. The study will also explore customer size thresholds that may apply should the DER class be partitioned by size. The study will be conducted in the attrition years to inform SCE's 2025 GRC Phase 2 Application and will include, but is not limited to, the following objectives:

1) Evaluate benefits of DER customers as a separate class. This evaluation may also consider if customers with similar load characteristics (i.e., those with load factors

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[7] CLECA recommends that cost-based Option E rates for TOU-8-SUB and TOU-8-PRI should be established when there are sufficient numbers of Option E customers on those schedules.

[8] 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.

or hourly usage profiles, and kW demands similar to DER customers) should also be grouped within the separate class;

2) Determine which service options (*i.e.,* EV, Option E, RTP, others) should be included in a DER rate class;

3) Study overall benefits of revenue allocation and rate design impacts associated with customers under the separate rate class treatment using the 2021 GRC Phase 2 costs and load studies, adjusted to reflect separate DER class(es), as the basis for the study; and

4) Align the study with applicable Commission's DER Action Plan 2.0 Vision Elements.

SCE will form a working group of interested parties to help develop the scope and analysis for, and to evaluate the results of, the DER rate class study. For example, the working group will help define which types of DERs to consider and which rate groups to evaluate and to include within the DER rate class, and will provide feedback on the analysis used and the results obtained.

4. <u>Default CPP Rate Design</u>

The Settling Parties do not modify the currently effective CPP rates. The currently effective CPP rates reflect changes to CPP program adopted in D.18-07-006 and D.21-03-056, and include the following:

- CPP event periods shall coincide with the current TOU peak periods (*i.e.*, maximum number of CPP events of up to 15 per year; and shall include weekends, holidays, and weekdays from 4-9 p.m.).
- CPP event charge of $0.80/kWh.
- Bill protection will be offered to customers for up to one year.

The Settlement Agreement does not limit other changes to the CPP program in the attrition years.

5. Legacy Option B and R (Option A and 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 PTO 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.

C. Standby Rate Design

1. Large Power 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 described above. 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 RES-BCT Generating Accounts (*i.e.*, the replacement of the current Option TOU-8-S-A with TOU-8-S-LG) is also maintained.

2. Medium Power Standby Rate Design

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 Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) customers).

The Settlement Agreement adopts the following rate design for Medium Power Standby customers:

The Settlement Agreement provides that 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 capacity reservation charge (CRC) shall be the lesser of the FRD Charge that is based on the customer's otherwise applicable tariff (OAT) 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. Renewable Energy Self-Generation Bill Credit Transfer (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.

D. EV Rate Design

Schedules TOU-EV-8 and TOU-EV-9 are separately metered rates applicable solely to the charging of EVs for customers. SCE proposed to extend the all 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 TEF guidance can be implemented as part of an RDW in this GRC cycle or in a separate rate design proceeding as determined by the CPUC, whichever occur 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. Specifically:

Settling Parties agree to extend the current versions of TOU-EV-8 and TOU-EV-9, beyond the five-year timeline established by D.18-05-040 for such an energy-only rate structure. Settling Parties also agree that this Settlement Agreement does not restrict the Commission from modifying TOU-EV-8 and TOU-EV-9 in any proceeding relating to transportation electrification. If the energy-only rate structures remain in effect at the time SCE files its next GRC Phase 2, then SCE shall either propose to begin a gradual phase-in of demand charges that is consistent with the phase-in process outlined in the Joint Stipulation as approved in D.18-05-040 or propose rate structure updates for TOU-EV-8 and TOU-EV-9 that address how demand charges should be implemented. Adjustments to account for customers participating in the TOU-EV-8 and TOU-EV-9 rates will be made such that the revenue deficiency is contained within the individual rate class (e.g., TOU-GS-2, TOU-GS-3, TOU-8) in which the deficiency exists. The energy-only rate structure shall also be offered to Direct Current Fast Charger (DCFC) to provide stability to the developing DCFC industry.

E. Real-Time Pricing (RTP) Rate Options

SCE proposed to not make any structural changes to the existing RTP rate options. No party, other than JARP and SBUA, submitted its own proposal. The Settlement Agreement provides: The RTP rate options shall continue to reflect the changes adopted in D.18-07-006.[9] Illustrative rates reflecting these changes and modifications to make the rates revenue neutral to the applicable rate classes are included in Appendix B.

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

SCE proposed 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). The Settlement Agreement adopts SCE's uncontested proposal.

G. Closing of Schedule GS-2 (Flat Rate)

The "flat" Schedule GS-2 remains open to 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 (ESC) meters in 2022 and migrate these customers to their applicable TOU-GS-2 rate schedule by 2024/2025.

The Settlement Agreement adopts SCE's uncontested proposal to close Schedule GS-2 upon completion of the migration.

H. Demand Response Credits (APS and BIP)

The Settlement Agreement adopts SCE's current rate structures and rate designs associated with SCE's demand response programs, *i.e.*, BIP and APS, shall reflect the respective incentive budgets at the current level as shown in Appendix B to the Settlement Agreement. BIP credits will be continued to be provided based on the difference between the customer's average on- and mid-peak demand and firm

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[9] This Settlement Agreement does not address or resolve the Real Time Pricing rate design proposals raised by JARP and SBUA.

service level, where the average on- and mid-peak demands are calculated by dividing the kWh usage in the period by the number of hours in the period.

I. Attrition Year Changes

As described in the Marginal Cost and Revenue Allocation Settlement Agreement,[10] 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.

IV.

REQUEST FOR ADOPTION OF THE SETTLEMENT

The Settlement Agreement is submitted pursuant to Rule 12.1 *et seq*. of the Commission's Rules of Practice and Procedure. The Settlement Agreement is also consistent with Commission decisions on settlements, which express the strong public policy favoring settlement of disputes if they are fair and reasonable in light of the whole record.[11] This policy supports many worthwhile goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing the Parties to reduce the risk that litigation will produce unacceptable results.[12] As long as a settlement taken as a whole is reasonable in light of the record, consistent with the law, and in the public interest, it should be

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[10] *See* Paragraph 4.B.7 of the Marginal Cost and Revenue Allocation Settlement Agreement. This settlement agreement was filed on December 13, 2021.

[11] *See, e.g.,* D.88-12-083 (30 CPUC 2d 189, 221-223) and D.91-05-029 (40 CPUC 2d, 301, 326).

[12] D.92-12-019, 46 CPUC 2d 538, 553.

adopted without change.

The Settlement Agreement complies with Commission guidelines and relevant precedent for settlements. The general criteria for Commission approval of settlements are stated in Rule 12.1(d) as follows:

> The Commission will not approve stipulations or settlements, whether contested or uncontested, unless the stipulation or settlement is reasonable in light of the whole record, consistent with law, and in the public interest.[13]

The Settlement Agreement meets the criteria for a settlement pursuant to Rule 12.1(d), as discussed below.

A. The Settlement Agreement is Reasonable In Light Of the Record

The prepared testimony, the Settlement Agreement itself, and this motion contain the information necessary for the Commission to find the Settlement Agreement reasonable in light of the record. Prior to the settlement, the Settling Parties conducted extensive discovery and served testimony on the issues related to medium and large power rate design. In a separate motion, any Settling Parties who have not yet done so will move to have the Commission admit their prepared testimony and related exhibits into the Commission's record in this proceeding.

The Settlement Agreement represents a reasonable compromise of the Settling Parties' positions. The prepared testimony of the Settling Parties, together with this motion and the attached Settlement Agreement (which includes the comparison exhibits), contain sufficient information for the Commission to judge the reasonableness of the settlement. Without divulging the content of confidential settlement negotiations, concessions by Settling Parties on some issues were offset by concessions by other Settling Parties on other issues, as is the case with almost every settlement. The Settlement Agreement accordingly represents a series of tradeoffs and must be viewed as a "package." No single provision should be viewed in isolation, although every individual provision is reasonable, lawful, and in the public interest. In summary, the Settlement Agreement is a reasonable compromise of the Settling Parties' respective positions, as summarized in Section III and discussed in the following sections.

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[13] *See also*, *Re San Diego Gas & Electric Company,* (D.90-08-068), 37 CPUC 2d 360.

The Settlement Agreement adopts several uncontested proposals relating to medium and large power rate design, including SCE's proposal to continue offering the same options under TOU-GS-2, TOU-GS-3, and TOU-8 and SCE's proposal to maintain current eligibility requirement for Option E. These proposals were not controversial, and the Settling Parties (as sophisticated rate design intervenors) chose not to address them in testimony (or actively supported them). The Commission should deem them to be reasonable.

As for the contested issues, Section III shows that there were several rate design related proposals that were heavily negotiated by the Settling Parties. For example, the development of rate design for Option E, parties reached a compromise by maintaining SCE's proposed rate design and introduce an energy scaler for TOU-GS-3 to capture some of the revenue responsibility shortfall associated with customers participating on Option E. Separately, Settling Parties agree that SCE shall perform a working group study during the attrition years to explore the potential of creating a separate DER customer class.

In sum, as a result of the compromises made and the balancing of interests, the Settlement Agreement reflects a reasonable resolution of the medium and large power rate design issues covered therein in light of the record.

B. The Settlement Agreement is Consistent with the Law

The Settling Parties believe that the terms of the Settlement Agreement comply with all applicable statutes and prior Commission decisions, and reasonable interpretations thereof. In agreeing to the terms of the Settlement Agreement, the Settling Parties have explicitly considered the relevant statutes and Commission decisions and believe that the Commission can approve the Settlement Agreement without violating applicable statutes or prior Commission decisions.

In particular, the Settling Parties believe that the settled position with regard to EV Rates is consistent with Decision (D.)18-05-040, where the Commission adopted a "Joint Stipulation"[14] outlining an agreed upon methodology for SCE's rate design for then-new EV rates, including the TOU-EV-8 and

[14] The signatories to the Joint Stipulation were Cal Advocates, Natural Resources Defense Council. Siemens, Sierra Club, Environmental Defense Fund and the Coalition of California Utility Employees.

-9 rates addressed in this Settlement Agreement. Specifically, D.18-05-040 provided (with emphasis added):

> [Ordering Paragraph] 43. ***Southern California Edison Company (SCE) may offer its Commercial Electric Vehicle Rate proposal as modified by the Joint Stipulation set forth in Exhibit Joint-12.*** SCE may offer the transmission related proposals in Exhibit Joint-12 on a temporary three-year basis, provided SCE files a Single Issue 205 filing with the Federal Energy Regulatory Commission (FERC) for approval of the 70/30 proxy temporary rates and takes the appropriate steps to complete a transmission marginal cost study in its General Rate Case phase 2.[15] In the event FERC does not approve the 70/30 proxy split, SCE may implement its proposed commercial rate EV rates using the transmission cost allocation currently approved by FERC.

On Nov. 20, 2018, SCE made a Single Issue 205 filing at FERC, in Docket No. ER19-374, to implement the new EV rates, including TOU-EV-8 and -9. As part of that filing, SCE stated that the energy-only rates would be voluntary, optional and in effect for five years, and that SCE would file a subsequent Single Issue 205 filing to establish the 70/30 proxy split in years 6-10.[16] SCE will make any necessary filings at FERC to ensure consistency with D.18-05-040 and the instant Settlement Agreement.

The Joint Stipulation adopted in D.18-05-040 provided as follows (with emphasis added):

> The Parties agree that the following method should be used for designing the New EV Rates [i.e., EV rate design proposed in A.17-01-021], which, if adopted by the Commission, would include provisions lasting over a ten-year period from the initial implementation. ***Specifically, the Parties agree that this ten-year term should consist of a five year introductory period with no demand charges followed by a five-year phase-in of demand charges.*** In addition, for the entire ten-year term the Parties agree that: (a) the general rate structure of the New EV Rates should consist of TOU energy charges, generation capacity recovered through TOU energy charges and non-bypassable charges recovered on a non-TOU energy basis; (b) for TOU-EV-7 Option B, TOU-EV-8, and TOU-EV-9, distribution costs should be recovered through grid and peak rate components and transmission costs recovered through grid and peak rate components; ***both the peak and grid components of distribution and transmission costs should be recovered through volumetric energy rates during the introductory period (years 1–5), whereas for years 6–10 the peak components should be recovered through volumetric TOU rates while the grid components should be recovered through demand charges.***
> …

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15 SCE filed this study in this GRC Phase 2. *See* Exhibit-SCE-02, Appendix F.

16 *See* Accession Number 20181120-5099, filed Nov. 18, 2018, Exhibit 1 (Declaration of Robert A. Thomas) at Paragraphs 8-9.

> ***This stipulation does not bind or limit any of the stipulating parties from presenting different proposals or taking different positions on issues related to EV rates that may be considered in SCE's GRC Phase 2 or elsewhere. All parties reserve the right to propose changes to the New EV Rates in SCE's GRC Phase 2*** or similar proceedings related to eligibility determinations, optional TOU periods, the level of Distribution (including Customer) and Generation marginal costs and their respective allocations subject to the limits in the previous paragraph.

As discussed in Section III.D of this Motion, Settling Parties agree to extend the energy-only structure of TOU-EV-8 and TOU-EV-9 beyond the five-year timeline initially established in D.18-05-040, a modification that is consistent with the Joint Stipulation's offramp for proposals made in a GRC Phase 2. The Settling Parties further agree that if the energy-only rate structures remain in effect at the time SCE files its next GRC Phase 2, then SCE shall either propose to begin the gradual introduction of demand charges or propose rate structure updates for TOU-EV-8 and TOU-EV-9 that address how demand charges should be implemented.[17]

C. The Settlement Agreement is in the Public Interest

The Settlement Agreement is a reasonable compromise of the Settling Parties' respective positions, as summarized in Section III. The Settlement Agreement is in the public interest and in the interest of SCE's customers. The Parties fairly represent the interests of the wide variety of customers and customer classes that are affected by the revenue allocation. The Agreement fairly resolves issues and provides more certainty to customers regarding their present and future costs, which is in the public interest.

The Settlement Agreement, if adopted by the Commission, avoids the cost of further litigation, and frees up Commission resources for other proceedings. Given that the Commission's workload is extensive, the impact on Commission resources is doubly important. The Settlement Agreement frees up the time and resources of the Commission and of the Parties, so that they may focus on other proceedings and the rate design portions of this proceeding. The prepared direct testimony contains sufficient information for the Commission to determine the reasonableness of the Settlement Agreement and to discharge any future regulatory obligation with respect to this matter.

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[17] Settling Parties also agree that this Settlement Agreement does not restrict the Commission from modifying TOU-EV-8 and TOU-EV-9 in any proceeding relating to transportation electrification.

D. <u>The Settlement Agreement Should Be Adopted as a Whole as it is a Compromise of Interests</u>

Each portion of the Settlement Agreement is dependent upon the other portions of the Settlement Agreement. Changes to one portion of the Settlement Agreement would alter the balance of interests and the mutually agreed-upon compromises and outcomes that are contained in the Settlement Agreement. As such, the Settling Parties request that the Settlement Agreement be adopted as a whole by the Commission, as it is reasonable in light of the whole record, consistent with law, and in the public interest.

V.

CONCLUSION

WHEREFORE, the Settling Parties respectfully request that the Assigned Commissioner, Assigned ALJs, and the Commission:

1. Approve the attached Settlement Agreement as reasonable in light of the record, consistent with law, and in the public interest; and

2. Authorize SCE to implement changes in rates and tariffs in accordance with the terms of the Settlement Agreement.

Respectfully submitted,

FADIA R. KHOURY
MATTHEW DWYER

/s/ Matthew Dwyer

By: Matthew Dwyer

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And on behalf of the Settling Parties pursuant to Rule 1.8(d).

February 18, 2022

Attachment A

Medium and Large Power Rate Group Rate Design Settlement Agreement

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	A.20-10-012 (Filed October 23, 2020)

MEDIUM AND LARGE POWER RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

Dated: **February 18, 2022**

Medium and Large Power Rate Group Rate Design Settlement Agreement

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) to Establish Marginal Costs, Allocate Revenues, and Design Rates.	A.20-10-012 (Filed October 23, 2020)

MEDIUM AND LARGE POWER RATE GROUP RATE DESIGN SETTLEMENT AGREEMENT

This Medium and Large Power Rate Group Rate Design Settlement Agreement (Agreement or Settlement Agreement) is entered into by and among the undersigned Parties hereto, with reference to the following:

1. PARTIES

The Parties to this Agreement are Southern California Edison Company (SCE); Federal Executive Agencies (FEA); California Large Energy Consumers Association (CLECA); Energy Users Forum (EUF); Solar Energy Industries Association (SEIA); the Energy Producers and Users Coalition (EPUC); California Manufacturers & Technology Association (CMTA); Direct Access Customer Coalition (DACC); EVgo Services LLC; and, Tesla, Inc. (referred to hereinafter collectively as Settling Parties or individually as a Party).

A. SCE is an investor-owned public utility (IOU) and is subject to the jurisdiction of the California Public Utilities Commission (Commission or CPUC) with respect to providing electric service to its CPUC-jurisdictional retail customers.

B. FEA represents the consumer interests of all federal executive agencies that take utility service from SCE, Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E).

C. CLECA is an organization of large, high-load factor industrial electric bundled service, Community Choice Aggregation (CCA) and Direct Access (DA) customers located throughout the state. These companies are in the steel, cement, industrial gas, pipeline, minerals extraction, cold storage, and beverage industries, and share the fact that electricity costs comprise a significant portion of their cost of production. CLECA members engage in the Base Interruptible Program and other demand response programs both to promote grid reliability and to help mitigate the impact of the high cost of electricity in California on the competitiveness of manufacturing.

D. DACC is a regulatory alliance of commercial, industrial and governmental customers who have opted for DA service for some or all of their electric loads.

E. EUF is an *ad hoc* group that represents the interests of medium and large bundled service and DA customers in California, with locations in IOU and/or municipal utility service areas, taking service on rate schedules primarily for accounts with demand above 100 kilowatts (kW).

F. CMTA is a trade association representing the interests of 25,000 large and small manufacturers in California and 1.2 million employees. Many of its members receive electrical service from SCE either bundled service or DA customers.

G. SEIA is the national trade association of the United States solar industry. Through outreach and education, SEIA and its 1,000 member companies work to make solar energy a mainstream and significant energy source by expanding markets, removing market barriers, strengthening the industry, and educating the public on the benefits of solar energy.

H. EPUC represents the end-use and customer generation interests of the following companies: Aera Energy LLC, Chevron U.S.A. Inc., California Resources Corporation, PBF Energy, Inc., and Phillips 66 Company.

I. EVgo owns and operates the largest network of public fast charging stations for electric vehicles, with over 800 station locations across the United States. In California, EVgo manages more than 300 fast charging locations and 750 fast chargers, connecting more than 80% of Californians to an EVgo fast charger within a 15-minute drive.

J. Tesla is a California based manufacturer of EVs and provider of charging infrastructure. Tesla's mission is to accelerate the world's transition to sustainable energy and has dedicated itself to electrifying transportation through the manufacture and sale of advanced electric vehicles as well as key clean energy technologies, including battery storage and solar photovoltaic systems.

2. DEFINITIONS

When used in initial capitalization in this Settlement Agreement, whether in singular or plural, the following terms shall have the meanings set forth below or, if not set forth below, then as they are defined elsewhere in this Settlement Agreement:

A. "AC" means "alternating current."

B. "Added Facilities" are customer-dedicated, SCE-maintained electrical distribution facilities as defined in SCE's Electric Rule 2 tariff.

C. "AL" means an Advice Filing, sometimes referred to as an Advice Letter filing, at the CPUC.

D. "APS" means Automatic Powershift.

E. "Backup Service" is the electric service that is provided by SCE to a customer who has an on-site generating facility during unscheduled outages of the customer's on-site generator.

F. "Base Interruptible Program" or "BIP" means the rate schedule applicable to customers with demands of 200 kW or more who receive a credit applied to their summer and winter season Time Related Demand (TRD) Charges in return for the customer's agreement to reduce its demand to a specified level within either 15 or 30 minutes of notification by SCE of the need to reduce load.

G. "Base Rate" means the rate option (*e.g.*, TOU-GS-3, Option D) in a rate class (*e.g.*, TOU-GS-3) against which all other options within the rate group are designed to be revenue-neutral.

H. "BTM" means "behind-the-meter."

I. "CAISO" means the California Independent System Operator.

J. "CA" means "Community Aggregation."

K. "Capacity Reservation Charge" or "CRC" means the charge assessed to Standby customers based on the customer's designated kW level of Standby Demand.

L. "CCA" means Community Choice Aggregation.

M. "C&I" means Commercial and Industrial customers.

N. "Cold Ironing" means the provision of electrical power for lights, heating, machinery or other needs of an ocean-going vessel at the Port of Long Beach or Port of Hueneme as replacement for the vessel's auxiliary internal combustion engines or to a truck at truck stops where the truck's internal combustion engine is turned off. For purposes of eligibility, the electric usage for Cold Ironing must be separately metered and at least 90 percent of the metered load must displace power generation associated with vessels or trucks that would otherwise be provided by internal combustion generation on the vessel or the truck (or as additionally designated in SCE's tariffs).

O. "Commission" or "CPUC" means the California Public Utilities Commission.

P. "Customer Charges" mean the fixed dollar-per-month charges applied to customers in the C&I rate classes that are designed to recover the fixed customer costs of connection to SCE's system.[1]

Q. "DA" means Direct Access.

R. "Default Rate" means the rate schedule on which the customer is automatically placed when starting service unless the customer requests otherwise.

S. "Demand Charges" mean those charges that are comprised of Facilities Related Demand (FRD) Charges and Time-Related Demand (TRD) Charges, which are based on the customer's maximum kW in any time period (*i.e.*, FRD), or during a specified time-of-use

[1] The term "customer" as used in this Agreement generally refers to a service account when used in the context of eligibility and the rates for a particular tariff or rate schedule.

(TOU) period (*i.e.*, TRD), within a billing period. Demand Charges recover a portion of SCE's distribution and generation costs, where such charges apply to a specific rate schedule.

T. "DDMC" or "Design Demand Marginal Costs" means the incremental cost associated with providing additional capacity on the distribution system.

U. "DER" means "Distributed Energy Resource."

V. "Distribution Grid" (or "Grid") refers to the portion of DDMCs that are not Distribution Peak-related.

W. "Distribution Peak" (or "Peak") refers to the portion of DDMCs that are primarily sized to support the time-sensitive nature of coincident peak demand on the distribution system.

X. "Energy Charges" mean the dollar-per-kilowatt-hour (kWh) charges that recover (1) the portion of SCE's generation services revenues not recovered in TRD Charges; (2) the portion of SCE's delivery services revenues that are not recovered in TRD, FRD or Customer Charges; and (3) other delivery services revenues for public purpose programs (including Energy Efficiency and California Alternate Rates For Energy (CARE), New System Generation Service (NSGS), Nuclear Decommissioning, CARE Balancing Account, Wildfire Fund Non-bypassable Charge, Fixed Recovery Charge, demand response programs, and CPUC reimbursement fees). TOU differentiated Energy Charges are designed to provide a price signal consistent with marginal cost differentials in TOU Energy Charges, where TOU Energy Charges apply to a specific schedule.

Y. "EPMC" means equal percent of marginal cost. Because marginal cost revenues do not equal the utility's revenue requirement, in general, the utility revenue requirement is allocated to different rate groups in proportion to each rate group's percentage share of marginal cost revenue responsibility by function (*i.e.*, separately for generation costs, and combined distribution and customer costs).

Z. "EV" means "electric vehicle."

AA. "Facilities Related Demand Charges" or "FRD Charges" mean the charges applied to customers' monthly peak demands that are not differentiated by TOU or by season, and that are designed to recover certain transmission and distribution costs that are defined to be unrelated to time of use.

BB. "FLT" means "final line transformer."

CC. "Functional SAPC Allocation" means allocation of SCE's revenue requirement to each of SCE's rate groups based on the system average percentage change (SAPC) for the particular function, *e.g.*, generation, or distribution and customer costs.

DD. "GCMC" means "generation capacity marginal costs."

EE. "Generation Peak" refers to the portion of GCMCs that are incurred to support the electric system during maximum system demand.

FF. "Large Power Rate Group" means the following SCE rate classes: (1) the TOU-8 rate classes, comprised of customers with demands that are more than 500 kW and are differentiated by service voltage as follows: TOU-8-Subtransmission (TOU-8-Sub), which is for service above 50 kV; TOU-8-Primary (TOU-8-Pri), which is for service from 2 kV to 50 kV; and TOU-8-Secondary (TOU-8-Sec), which is for service below 2 kV; and (2) the three TOU-8-Standby (TOU-8-S) rate classes, with service voltage differentiation being the same as the three TOU-8 rate classes.

GG. "Medium Power Rate Group" means the TOU-GS-2 rate class, which is comprised of C&I customers with demands of more than 20 kW but less than 200 kW, and the TOU-GS-3 rate class, which is comprised of C&I customers with demands between 200 kW and 500 kW.

HH. "OAT" means the customer's otherwise applicable tariff.

II. "Paired storage" means BTM electric storage technology including, but not limited to, electric battery systems, that are combined behind the same meter or billed on the same service account as other DERs, usually solar.

JJ. "PLS" or "Permanent Load Shift" means technologies that are installed to allow customers to shift load that would otherwise occur during peak periods to off-peak periods on a permanent basis.

KK. "PLRF" means "Peak Load Risk Factor," and represents the methodology used to assess capacity constraints on the distribution system and to assign peak-capacity-related design demand marginal costs to TOU periods.

LL. "RA Settlement Agreement" means the Marginal Cost and Revenue Allocation Settlement Agreement filed in this proceeding on December 13, 2021.

MM. "RDW" means Rate Design Window proceeding.

NN. "Renewable Distributed Generation Technologies" means renewable generation technology as defined in the Statewide California Solar Initiative (CSI), the Self-Generation Incentive Program (SGIP), or their successors.

OO. "RECC" or "Real Economic Carrying Charge," means a constant payment in real dollars that includes the recovery of the capital investment, earnings, taxes, and other capital carrying costs. The RECC when escalated at the rate of inflation over the life of the asset recovers the net present value of revenue requirement of a utility investment. It also represents the value of deferring a utility investment by a year.

PP. "RTP" means Real Time Pricing.

QQ. "Standby Algorithm," or "Algorithm" is the algorithm adopted by the CPUC in D.16-03-030, approving SCE's 2015 GRC Phase 2.

RR. "Standby Demand Backup Charge" are TRD Charges based on the lesser of the Standby Demand or the maximum Backup Demand for the relevant TRD period calculated for each 15-minute interval as the difference between the 15-minute interval maximum SCE metered demand (kW) and the 15-minute interval Intermediate Supplemental Demand, but not less than zero.

SS. "Standalone storage" means BTM electric storage technology including, but not limited to, electric battery systems that are not combined behind the same meter or billed on the same service account as other DERs.

TT. "SCC" or Supplemental Contract Capacity is the level of kW regularly served by SCE for Standby customers.

UU. "Time-Related Demand Charges" or "TRD Charges" are generation or distribution marginal-cost-based, capacity-related charges assigned to TOU periods based on loss-of-load probabilities during the TOU periods.

VV. "TOU" means time-of-use. TOU periods are the time periods established for the provision of electric service in which Demand Charges or Energy Charges may vary in relation to the cost of service, and reflect the TOU periods adopted in D. 17-08-006.

WW. "ZEV" means Zero-Emissions Vehicle.

3. RECITALS

A. In Phase 2 of SCE's 2021 General Rate Case (GRC), the Commission allocates SCE's authorized revenue requirement among rate groups and authorizes rate design changes for rate schedules in each rate group.

B. On October 23, 2020, SCE served its initial prepared testimony regarding marginal costs, revenue allocation and rate design in Application (A.)20-10-012.

C. On January 21, 2021, the Assigned Commissioner and Assigned Administrative Law Judge issued a Scoping Memo and Ruling following a December 16, 2020 prehearing conference.

D. The Public Advocates Office served its initial testimony on June 24, 2021. Intervenors, including the Settling Parties to this Agreement, served their initial prepared testimony on July 26, 2021.

E. The following intervenors submitted prepared testimony regarding Medium and Large Power Rate Design Issues: CLECA, and EPUC.

F. SCE provided notice to all parties of its intent to conduct a settlement conference related to all issues raised in the proceeding, and an initial settlement conference was held on August 12, 2021.

G. Continuing settlement discussions occurred among the parties after August 12, 2021. Specific to this Settlement Agreement, the Settling Parties commenced settlement discussions on September 14, 2021.

H. Appendix A to this Agreement provides a comparison of the Settling Parties' positions, where applicable, related to Medium and Large Power Rate Group rate design issues that have been resolved by this Agreement. In the event of a conflict between the terms of this Agreement and Appendix A, the terms of this Agreement shall control. Appendix B provides illustrative Medium and Large Power Rate Group rates resulting from this Settlement Agreement. Consistent with Paragraph 11 of this Settlement Agreement, these class average summaries are for illustrative purposes only. The rate summaries will be adjusted to reflect SCE's actual revenue requirements in accordance with the provisions of the RA Settlement Agreement when rates are first implemented pursuant to the provisions of this Agreement.

I. The Settling Parties have evaluated the impacts of the various proposals in this proceeding and desire to resolve all issues related to rate design regarding Medium and Large Power Rate Group customers as set forth in this Agreement beginning with the implementation of a CPUC decision approving this Agreement,[2] and, in consideration of the mutual obligations, covenants and conditions contained herein, have reached agreement as indicated in Paragraphs 4 and thereafter of this Agreement.

4. AGREEMENT

Nothing in this Agreement shall be deemed to constitute an admission by any Settling Party that its position on any issue lacks merit, or a claim by a Settling Party that its position has greater or lesser merit than the position taken by any other Settling Party. This Agreement is subject to the express limitation on precedent as provided in Commission Rule 12.5 and as described in Paragraph 11. Unless specifically stated otherwise herein, this Agreement and its terms are intended to remain in effect until a decision is implemented in Phase 2 of SCE's next GRC.

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[2] Except for (1) Real Time Pricing rate design proposals raised by California Solar and Storage Association, Enel X North America, Inc., and Tesla, Inc. (collectively, the "Joint Advanced Rate Parties" or "JARP") and Small Business Utility Advocates (SBUA), and (2) SEIA's proposal to implement an Option S storage rate with daily demand charges.

A. Illustrative Rates

The Settling Parties agree that the results of the rate design process illustrated by the rate schedules in Appendix B to this Agreement are reasonable. These rates are based on the Medium Power and Large Power Rate Groups' share of the consolidated revenue requirement of $14,388 million described in more detail in Paragraph 4.B of the RA Settlement Agreement. These illustrative rates shall be adjusted consistent with the terms of this Agreement and the CPUC's decision in this proceeding related to the RA Settlement Agreement to reflect SCE's actual total system revenue requirement when this Agreement is implemented.

B. Common Rate Design Elements

Consistent with SCE's Application, rate structures for the Medium and Large Power Rate Groups will generally consist of Customer Charges, TOU Energy Charges, TRD Charges, and FRD Charges. Default CPP rate schedules will continue to apply to the TOU-GS-2, TOU-GS-3 and TOU-8 rate classes.[3] Optional RTP rate schedules will also continue to be available. Finally, accounts eligible for legacy TOU period rate option in accordance with D.17-01-006 and D.17-10-018 will remain on Legacy Option A, Option B, and/or Option R until the end of their legacy period.

1) TOU Periods and Seasonal Definitions

SCE's existing TOU periods and summer/winter season definitions for C&I customers shall not be modified from their current definitions. (*i.e.,* summer: June through September; winter: October through May).

2) Customer Charges

Customer Charges shall be derived based on SCE's as-proposed RECC customer marginal cost method, but adjusted to recover a portion (*i.e.*, the first 50 kVA) of the FLT costs in the

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[3] D.18-07-006 resolving SCE's 2016 RDW Application approved default CPP for the TOU-GS-2 Rate Class. Customers must have been served on a TOU rate for at least 24 months before they are eligible for default CPP. Additionally, customers with pending DA, CCA or CA enrollments are not subject to default CPP, as provided in D.18-07-006.

FRD Charge. Customer Charges shall be set at the full EPMC level for all customers in the Medium and Large Power Rate Groups. Illustrative monthly Customer Charges are listed in Table C&I-1, below:

Table C&I-1
Illustrative Monthly Customer Charges[4]

Rate Group	Customer Charge
Flat GS-2	$171.75
TOU-GS-2	$171.75
TOU-GS-3	$505.50
TOU-8-SEC	$319.75
TOU-8-PRI	$304.00
TOU-8-SUB	$2,596.75

When this Agreement is first implemented in 2022, these estimated Customer Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with the RA Settlement Agreement.[5] Thereafter, these Customer Charges shall be adjusted on a Functional SAPC basis.

3) Energy Charges

Proposed Energy Charges based on SCE's 2021 consolidated revenue requirement are set forth in Appendix B.[6] When this Agreement is first implemented in 2022, these estimated Energy Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with the RA Settlement Agreement.[7] Thereafter, these estimated Energy Charges shall be adjusted consistent with Paragraph 4.B.7 of the RA Settlement Agreement when SCE's authorized revenue requirements change.

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4 Illustrative Customer Charges for the Standby TOU-8-Sec, -Pri, and -Sub rate classes are equal to the Customer Charges for the corresponding TOU-8-Sec, -Pri, and -Sub rate classes, and are shown in Appendix B.

5 *See* Paragraph 4.B.6 of the RA Settlement Agreement.

6 The estimated consolidated revenue requirement, as defined in Paragraph 4.B.1 of the RA Settlement Agreement, is $14,388 million.

7 *See* Paragraph 4.B.6 of the RA Settlement Agreement.

a) **Non-Generation-Related Energy Charges**

Energy Charges that are designed to recover revenues associated with the following categories -- transmission (TOTCA), distribution,[8] public purpose programs, new system generation service, nuclear decommissioning, Wildfire Fund Non-bypassable Charge, Fixed Recovery Charge, and the CPUC reimbursement fee -- shall be established on the basis of the specific functional authorized revenue requirements and the terms specified in the RA Settlement Agreement.

b) **Generation-Related Energy Charges**

Except where otherwise specified in this Agreement, generation-related Energy Charges shall be established based on the TOU marginal energy costs used in the RA Settlement Agreement.

4) **Demand Charges**

Demand Charges shall consist of TRD Charges 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 period.

a) **TRD Charges**

The base rate (*i.e.,* Option D) option for each rate class will continue to collect most generation capacity costs via TRD Charges and shall continue to apply both in the summer on-peak period and also in the winter mid-peak period.[9] The amount of generation revenues recovered via TRD Charges is discussed for each rate class in the "Base and Optional Rates and Rate Design" section below. Additionally, this Settlement Agreement continues to establish distribution TRD Charges in both the summer on-peak and winter mid-peak periods. The amount of distribution revenues recovered via the distribution TRD Charges is discussed for each rate class in the "Base and Optional Rates and Rate Design" section below.

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[8] The recovery of distribution revenues via Energy Charges varies based on the specific rate option, and is further discussed in the "Base and Optional Rates and Rate Design" section below.

[9] TRD charges do not apply on weekends or holidays in the winter mid-peak period.

Table C&I-2
Illustrative TRD Charges (Option D)[10]

	TOU-GS-2	TOU-GS-3	TOU-8-Sec	TOU-8-Pri	TOU-8-Sub
Summer On-Peak ($/kW)	27.52	31.73	30.59	30.75	21.23
Winter Mid-Peak ($/kW)	6.33	8.13	7.53	8.48	5.65

Table C&I-3
Estimated Backup and Supplemental TRD Charges for Standby (Based on Option D)[11]

	TOU-8-S-Sec	TOU-8-S-Pri	TOU-8-S-Sub
Backup Summer On-Peak ($/kW)	28.63	24.08	6.90
Backup Winter Mid-Peak $/kW	9.66	3.97	2.87
Supplemental Summer On-Peak $/kW	30.59	30.75	21.23
Supplemental Winter Mid-Peak $/kW	7.53	8.48	5.65

To offer customers a menu of rate options, this Settlement Agreement continues to make available "Option E" rates (with eligibility restrictions for the TOU-8 rate classes, as discussed below), which include a lower generation TRD charge compared to Option D and no distribution TRD Charge. The Option E TRD Charge is set at twenty-five percent (25%) of the Standby backup demand charge for each rate class. As part of this Agreement, SCE agrees to perform a DER Class Study during the attrition year as described in Paragraph 4.K, below.

[10] These TRD Charges combine both the generation and distribution TRD amounts; the individual components are provided in Appendix B.

[11] These TRD Charges combine both the generation and distribution TRD amounts; the individual components are provided in Appendix B.

Table C&I-4
Illustrative Generation TRD Charges (Option E)

	TOU-GS-2	TOU-GS-3	TOU-8-Sec	TOU-8-Pri	TOU-8-Sub
Summer On-Peak ($/kW)	4.08	4.44	4.17	3.41	1.36
Winter Mid-Peak ($/kW)	1.64	2.10	1.89	0.59	0.67

When this Agreement is first implemented, the illustrative TRD Charges shall be adjusted, as necessary, consistent with the then-current revenues allocated to each rate group in accordance with the RA Settlement Agreement.[12] Thereafter, these TRD Charges shall be adjusted consistent with Paragraph 4.B.7 of the RA Settlement Agreement for each individual rate class when SCE's authorized generation and distribution revenues change.

b) FRD Charges

Both Options D and E (and the Standby rate options) include a non-coincident FRD Charge (also CRC Charges for Standby), which this Agreement maintains to recover certain allocated delivery revenues, including SCE's base transmission revenues as adopted in FERC proceedings, for the TOU-GS-2, TOU-GS-3, and TOU-8 rate classes. For distribution-related revenues, with the exception of the TOU-8-Sub rate class, all other rates for medium and large power rate classes utilize the FRD Charge to recover only Distribution Grid-related costs in the Option D rate designs. For TOU-8-Sub, Option D, the FRD Charge recovers Distribution Grid-related costs and non-peak (*i.e.,* summer mid- and off-peak and winter off- and SOP-peak) distribution capacity costs. For the Option E rates, with the exception of TOU-8-Sub, 30 percent of distribution revenues are recovered via the FRD Charge. For TOU-8-Sub, Option E, only Distribution Grid-related costs are recovered via the FRD Charge.

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[12] *See* Paragraph 4.B.6 of the RA Settlement Agreement.

Table C&I-5
Illustrative FRD Charges (Option D)

	TOU-GS-2	TOU-GS-3	TOU-8-Sec	TOU-8-Pri	TOU-8-Sub
FRD Charge ($/kW)	19.05	17.92	18.96	18.02	8.99

Table C&I-6
Illustrative CRC and FRD Charges for Standby (based on Option D)

	TOU-8-S-Sec	TOU-8-S-Pri	TOU-8-S-Sub
FRD Charge ($/kW)	18.96	18.02	8.99
CRC Charge ($/kW)	16.48	10.04	0.99

Table C&I-7
Illustrative FRD Charges (Option E)

	TOU-GS-2	TOU-GS-3	TOU-8-Sec	TOU-8-Pri	TOU-8-Sub
FRD Charge ($/kW)	10.99	11.48	11.94	11.50	7.12

5) Voltage Discounts

Customers served at higher voltage delivery levels than the design voltage level for their rate group will receive a voltage discount reflecting their relatively 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 group and the higher voltage service options. Voltage discounts shall apply to rate schedules in the TOU-GS-2, TOU-GS-3, TOU-8, and TOU-8-S rate classes, as indicated in Appendix B. SCE will implement a refinement to the time-related demand voltage discounts. The refinement will differentiate the voltage discount into seasonal summer and winter voltage discounts for all rate options.[13] The current voltage discounts are not differentiated by season. The summer voltage discount will be applied to the summer on-peak period and the winter voltage

[13] Except for legacy rate options where the voltage discounts will be left unchanged.

discount will be applied to the winter mid-peak period, consistent with the way TRD charges are assessed.[14] The TOU-8 and Standby rate classes have voltage-differentiated rates, as reflected in the applicable tariffs, with the exception of service provided at the 220 kV level or higher.

6) <u>Power Factor Adjustments</u>

The method for determining power factor adjustment rates will be revised to more closely reflect SCE's cost of correcting poor power factor conditions, as indicated in Exhibit SCE-04. Power factor adjustments paid by certain customers shall be as proposed by SCE in its testimony, which is \$0.66 \$/kVAR for service at or above 50 kV and \$0.52/kVAR for service at less than 50 kV.[15]

7) <u>Base Distribution Facilities Related Demand and Energy Charges Adjustments</u>

For TOU-8 Option D rate schedules,[16] where distribution service revenue recovery is reflected through base rates that are charged on a cents per kWh basis (energy charge), and a dollar per kW basis (demand charge), SCE shall provide an offset whereby SCE will subtract from existing distribution energy charges an amount equivalent to the Fixed Recovery Charge[17] on a cent-per-kWh basis. The revenue imbalance of distribution base revenues created by this adjustment will be recovered through a commensurate adjustment of the non-coincident peak demand charges on a dollar-per-kW basis. By making this adjustment, customers in the applicable rate classes will experience an upward, or downward, adjustment to their demand charges with the offset in distribution energy charges, assuming no other changes to overall revenue requirement or revenue allocation to the class.[18]

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[14] Voltage discounts do not apply on weekends or holidays in the winter mid-peak period.

[15] Exhibit SCE-04, p. 16.

[16] This includes TOU-8-SUB.

[17] Fixed Recovery Charge refers fixed recovery charges defined in Public Utilities Code Section 850(b)(7) and authorized by the Commission pursuant to Public Utilities Code Section 850(a)(2).

[18] This mechanism retains the energy-only structure of the fixed recovery charge approved in D.20-11-007 and D.21-10-025, while satisfying EPUC's request for a distribution demand charge adjustment. *See e.g.*, D.20-11-007 at 80 ("we find that EPUC's request for a demand charge should be addressed in SCE's upcoming [2021] GRC Phase 2 proceeding or some other appropriate proceeding as the Commission may designate.").

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

1) Option D Base Rate -- Eligibility Requirements and Rate Design

a) Option D Eligibility for TOU-GS-2 and TOU-GS-3

Existing eligibility requirements are maintained (*i.e.,* C&I customers with demands above 20 kW up to 500 kW with no other eligibility restrictions).

b) Option D Rate Design for TOU-GS-2 and TOU-GS-3

Option D incorporates the following rate design:

- Current TOU periods 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 (5%) of off-peak capacity costs; a winter mid-peak TRD charge that recovers all winter peak capacity costs; TOU Energy Charges to recover ninety-five percent (95%) of summer off-peak capacity costs across all TOU periods; and the use of an FRD Charge to recover Grid-related costs.
- 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.

c) Option D Eligibility for TOU-8

Existing eligibility requirements are maintained (*i.e.,* C&I customers with demands exceeding 500 kW but excluding certain large water pumping and agricultural customers).

d) <u>**Option D Rate Design for TOU-8**</u>

Option D incorporates the following rate design for *TOU-8-Sec* and *TOU-8-Pri*:

- Current TOU periods adopted in D.18-07-006.
- A Customer Charge as set forth in Appendix B hereto.
- For distribution, a summer on-peak TRD Charge that recovers summer on, mid- and five percent (5%) of off-peak capacity costs, a winter mid-peak TRD Charge that recovers all winter peak capacity costs, TOU Energy Charges to recover ninety-five percent (95%) of summer off-peak capacity costs across all TOU periods, and the use of an FRD Charge to recover Grid-related costs.
- For generation, the rate design is consistent with the generation rate design for Option D of the TOU-GS-2 and TOU-GS-3 rate classes, as described above.

Option D incorporates the following rate design for *TOU-8-Sub*:

- Current TOU periods adopted in D.18-07-006.
- A Customer Charge as set forth in Appendix B hereto.
- For distribution, a summer on-peak TRD Charge that recovers summer on-peak capacity costs, a winter mid-peak TRD charge that recovers all winter mid-peak capacity costs, and an FRD Charge that recovers Grid-related costs and summer mid- and off-peak and winter off- and SOP-peak capacity costs (no distribution costs are recovered via Energy Charges).
- For generation, the rate design is consistent with the generation rate design for Option D of the TOU-GS-2 and TOU-GS-3 rate classes, as described above.

2) **<u>Option E Optional Rate – Eligibility Requirements and Rate Design</u>**

a) **<u>Option E Eligibility for TOU-GS-2 and TOU-GS-3</u>**

The current eligibility criteria (*i.e.*, C&I customers with demands above 20 kW up to 500 kW) is retained for this Settlement Agreement. Customers both with and without DERs are also eligible for Option E, and those receiving service on Option E are exempt from being required to take service on a Standby rate schedule.

b) **<u>Option E Rate Design for TOU-GS-2 and TOU-GS-3</u>**

Option E incorporates the following rate design:

- Current TOU periods 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, recovery of sixty percent (60%) of revenues (excluding Customer Charge revenues) via TOU Energy Charges using SCE's as-proposed PLRFs, thirty percent (30%) via an FRD Charge, and ten percent (10%) via flat cent-per-kWh Energy Charges.
- For generation, recovery of energy and capacity revenues is via a TRD Charge set at twenty-five percent (25%) of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges.

c) **<u>TOU-GS-3 Energy Rate Scalar</u>**

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 twenty-five percent (25%) 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 EPMC 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 below.

d) Option E Eligibility for TOU-8

- Option E eligibility is limited to customers who:
  - Participate in PLS (eligible systems must account for at least 15 percent of the customer's annual peak demand, as recorded over the previous 12 months), cold ironing pollution mitigation programs or the charging of eligible ZEVs intended for the transport of people or goods.
  - Install, own, or operate solar, wind, fuel cells or other eligible onsite Renewable Distributed Generation Technologies as defined by CSI or SGIP, including paired storage systems. zAn eligible customer's system must have a net renewable generating capacity equal to or greater than 15 percent of the customer's annual peak demand, as recorded over the previous 12 months.
  - Install standalone storage. An eligible customer's system must have a minimum discharge capacity equal to or greater than 20 percent of the customer's annual peak demand, as recorded over the previous 12 months.
- Eligibility for Option E is further limited to customers with annual peak demands not exceeding 5 MWs.

- Customers receiving service on Option E are exempt from being required to take service on a Standby rate schedule.
- A 250 MW participation cap will be maintained for customers with DER technologies. The capacity of new and existing customers who are utilizing PLS, cold-ironing, eligible ZEVs technologies will not be counted against the cap.
  - For DERs, the qualifying capacity counted towards the 250 MW participation cap is based on the system's AC nameplate rating.
  - For standalone storage, the qualifying capacity counted towards the cap is the discharge capacity of the storage system.
  - For paired storage systems, the qualifying capacity counted towards the cap is the larger of the system's AC nameplate solar capacity or the discharge capacity of the discharge storage system (but not both).
  - SCE agrees to file information-only ALs to report on the progress towards the cap. The frequency of such ALs will be one for every 50 MW of allocated capacity (based on the date of the signed interconnection agreement for the DER) until 200 MW is reached, at which time SCE will file monthly ALs until the cap is reached. The monthly ALs will include additional data to help inform actual progress towards the cap, *e.g.,* such as how long systems have been allocated capacity under the 250 MW cap but have not yet received permission to operate (PTO).

e) <u>Option E Rate Design for TOU-8</u>

Option E rate design for *TOU-8-Sec* and *TOU-8-Pri* is identical to the rate design described above for TOU-GS-2 and TOU-GS-3 Option E.

<u>Option E for *TOU-8-Sub* incorporates the following rate design:</u>

- Current TOU periods adopted in D.18-07-006.
- A Customer Charge as set forth in Appendix B.
- For distribution, an FRD Charge is used to recover Grid-related costs with the remaining revenue recovered via TOU Energy Charges using SCE's as-proposed PLRFs
- For generation, recovery of energy and capacity revenues is via a TRD Charge set at twenty-five percent (25%) of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges.

3) <u>Default Critical Peak Pricing (CPP) Rate Design</u>

The Settling Parties agree to not modify the currently effective CPP rates which reflect changes to CPP program adopted in D.18-07-006 and D.21-03-056. The current effective rates include:

- CPP event periods shall coincide with the current TOU peak periods (*i.e.*, maximum number of CPP events up to 15 per year; shall include weekends, holidays, and weekdays from 4-9 p.m.);
- CPP event charge of $0.80/kWh
- Bill protection will be offered to customers for up to one year.

This agreement does not limit other changes to the CPP program in the attrition years.

4) <u>Legacy Options B and R (Option A and B for Standby)</u>

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. Eligible solar customers may be served on legacy rates for ten years from their individual PTO dates, but not to exceed July 31, 2027 (non-public agencies) or December 31, 2027 (public agencies), as established in D.17-01-006 and D.17-10-018. No structural changes to the Legacy Options are adopted in this Agreement.

D. Standby Rate Design

1) Large Power

Standby customers with demands of more than 500 kW are classified into three rate classes, which are differentiated by the voltage at which service is provided. These rate groups are designated as TOU-8-Standby-Sec, TOU-8-Standby-Pri, and TOU-8-Standby-Sub. Standby customers with demands of more than 500 kW who elect service under a RTP option will be placed on Schedule TOU-8-RTP-S. The method for determining standby billing attributes (*i.e.*, Standby Demand and Supplemental Contract Capacity) used in SCE's Standby rate was fundamentally altered in SCE's 2015 GRC Phase 2 (approved by D.16-03-030). This Settlement Agreement does not structurally change the Standby rate design, nor does it change the method for determining billing attributes. Instead, in this Settlement Agreement, the Parties agree that 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 described above. SCE will continue to apply the Algorithm adopted in the 2015 GRC Phase 2 to determine Standby Demand and Supplemental Contract Capacity.

a) TOU-8-LG RES-BCT Service for Customers with Demands Greater than 500 kW

The Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) program is statutorily mandated and requires SCE to offer a tariff that allows local governments and campuses to generate electricity from an eligible renewable generating facility for their own use, and to export energy not consumed at the time of generation to SCE's grid. All such generation exported to SCE's grid is converted into bill credits and applied to benefiting accounts as designated by the local government or campus. RES-BCT service does not represent a form of NEM service, and thus customers taking RES-BCT service are not exempt from Standby service. Eligibility for Schedule TOU-8 Standby Option LG will continue to be limited to customers taking service on Schedule RES-

BCT (*i.e.*, the generating account only). This RES-BCT Option will be closed to new customers (in all rate groups eligible for this option) upon SCE reaching 125 MW of eligible installed capacity, representing SCE's designated share of the 250 MW statewide RES-BCT capacity cap.

(1) <u>TRD Charges</u>

TRD Charges for TOU-8 Standby, Option LG will apply only to Backup Service and shall be designed consistent with the TRD Charges for Option D for the corresponding TOU-8 rate classes.

(2) <u>Energy Charges</u>

All kWh usage for Standby Service, whether for Supplemental, Backup, or Maintenance Service, will be charged Supplemental Energy Charges that are determined consistent with the Energy Charges for the corresponding TOU-8 rate classes. The energy rates for Schedule TOU-8 Standby, Option LG, shall be structured to recover Supplemental generation-related capacity costs, in addition to generation-related energy costs, through volumetric Energy Charges on a cents-per-kWh basis.

2) <u>Medium Power</u>

Standby customers whose demands are 500 kW or lower will be treated similarly to customers in the TOU-8-S rate classes, with respect to the general applicability of Standby Service and determination of billing determinants. However, such customers 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 OAT 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 schedule.

E. EV Rates

1) Schedule TOU-EV-8/TOU-EV-9

Schedules TOU-EV-8 and TOU-EV-9 are separately metered rates applicable solely to the charging of EVs for customers. With regard to distribution charges, SCE will continue to offer a feature that limits distribution charges for TOU-EV-8 and TOU-EV-9 customers. The current versions of TOU-EV-8 and TOU-EV-9 reflect an energy-only rate structure. D.18-05-040 contemplated ending this energy-only rate structure, and beginning a gradual introduction of demand charges, five years after these two rates were originally authorized. Settling Parties agree to extend the current versions of TOU-EV-8 and TOU-EV-9, beyond the five-year timeline established by D.18-05-040 for such an energy-only rate structure. Settling Parties also agree that this Settlement Agreement does not restrict the Commission from modifying TOU-EV-8 and TOU-EV-9 in any proceeding relating to transportation electrification. If the energy-only rate structures remain in effect at the time SCE files its next GRC Phase 2, then SCE shall either propose to begin a gradual phase-in of demand charges that is consistent with the phase-in process outlined in the Joint Stipulation as approved in D.18-05-040 or propose rate structure updates for TOU-EV-8 and TOU-EV-9 that address how demand charges should be implemented.[19] Adjustments to account for customers participating in the TOU-EV-8 and TOU-EV-9 rates will be made such that the revenue deficiency is contained within the individual rate class (*e.g., TOU-GS-2, TOU-GS-3, TOU-8)* in which the deficiency exists. The energy-only rate structure shall also be offered to Direct Current Fast Charger (DCFC) to provide stability to the developing DCFC industry.

F. Real Time Pricing (RTP) Rate Options (including TOU-8-RTP / TOU-8-RTP-S)

The RTP rate options shall continue to reflect the changes adopted in D.18-07-006.[20] Illustrative rates reflecting these changes and modifications to make the rates revenue neutral to the applicable rate classes are included in Appendix B.

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[19] Such a proposal shall be consistent with any previously issued Commission decision(s) concerning TOU-EV-8 and TOU-EV-9.

[20] This Settlement Agreement does not address or resolve the Real Time Pricing rate design proposals raised by JARP and SBUA.

G. Schedule TOU-8-RBU (Reliability Back-up Service)

Schedule TOU-8-RBU provides customers with a service connection in addition to the customer's regular service connections, which is to be used solely for reliability or "back-up" purposes. The rate includes a nominal Customer Charge, Energy Charges, and generation TRD Charges, with no recovery of Distribution Design Demand charges in Energy or FRD Charges. The additional meter and service connection are installed in accordance with the Added Facilities provisions of SCE's Rule 2. This schedule shall be retained with adjustments to charges that are consistent with other schedules in the TOU-8 rate class.

H. Closing of Schedule GS-2 (Flat Rate)

The "flat" Schedule GS-2 remains open to 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 (ESC) meters in 2022 and migrate these customers to their applicable TOU-GS-2 rate schedule by 2024/2025. SCE shall close Schedule GS-2 upon completion of the migration.

I. Optimal Billing Period

The Optimal Billing Period shall be retained, allowing customers to align their billing and production cycles twice within a six-month period.

J. Demand Response Credits (APS and BIP)

Rate structures and rate designs associated with SCE's demand response programs, *e.g.*, BIP and APS, shall reflect the respective incentive budgets at the current level as shown in Appendix B. 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 kWh usage in the period by the number of hours in the period. Illustrative rates are included in Appendix B.

K. Attrition Year DER Class Study

Settling Parties agree that SCE, in consultation with a working group formed of representatives of Settling Parties or any other interested parties, shall perform a study to explore the potential of creating a separate DER customer class.[21] In the study, SCE will examine possible class definitions for DER customers and perform marginal cost-based allocation and rate setting for the resulting groups. The study will determine which types of customers, or services, should be categorized in a potential DER class. The study will also explore customer size thresholds that may apply should the DER class be partitioned by size. The study will be conducted in the attrition years to inform SCE's 2025 GRC Phase 2 Application and will include, but is not limited to, the following objectives:

1) Evaluate benefits of DER customers as a separate class. This evaluation may also consider if customers with similar load characteristics (i.e., those with load factors or hourly usage profiles, and kW demands similar to DER customers) should also be grouped within the separate class;
2) Determine which service options (*i.e.,* EV, Option E, RTP, others) should be included in a DER rate class;
3) Study overall benefits of revenue allocation and rate design impacts associated with customers under the separate rate class treatment using the 2021 GRC Phase 2 costs and load studies, adjusted to reflect separate DER class(es), as the basis for the study; and
4) Align the study with applicable Commission's DER Action Plan 2.0 Vision Elements.

SCE will form a working group of interested parties to help develop the scope and analysis for, and to evaluate the results of, the DER rate class study. For example, the working group

[21] 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.

will help define which types of DERs to consider and which rate groups to evaluate and to include within the DER rate class, and will provide feedback on the analysis used and the results obtained.

L. Implementing Future Revenue Changes in Rates

As described in the RA Settlement Agreement,[22] 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 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, except for TOU-GS-3 as specified in Paragraph 4.C.2 above.

5. IMPLEMENTATION OF SETTLEMENT AGREEMENT

It is the intent of the Settling Parties that SCE should be authorized to implement the rates resulting from this Settlement Agreement as soon as practicable following the issuance of a final Commission decision approving this Settlement Agreement, but no earlier than June 1, 2022.

6. INCORPORATION OF COMPLETE AGREEMENT

This Agreement is to be treated as a complete package and not as a collection of separate agreements on discrete issues. To accommodate the interests related to diverse issues, the Settling Parties acknowledge that changes, concessions, or compromises by a Settling Party or Settling Parties in one section of this Agreement resulted in changes, concessions, or compromises by the Settling Parties in other sections. Consequently, the Settling Parties agree to oppose any modification of this Agreement

[22] *See* Paragraph 4.B.7 of the RA Settlement Agreement.

not agreed to by all Settling Parties. If the Commission does not approve this Agreement without modification, the terms and conditions reflected in this Agreement shall no longer apply to the Settling Parties.

7. RECORD EVIDENCE

The Settling Parties request that all of their related prepared testimony be admitted as part of the evidentiary record for this proceeding.

8. SIGNATURE DATE

This Settlement Agreement shall become binding as of the last signature date of the Settling Parties.

9. REGULATORY APPROVAL

The Settling Parties, by signing this Agreement, acknowledge that they support Commission approval of this Agreement and subsequent implementation of all the provisions of the Agreement for the duration of rates implemented pursuant to a Commission order adopting this Agreement in this proceeding, *i.e.*, Phase 2 of SCE's Test Year 2021 GRC. The Settling Parties shall use their best efforts to obtain Commission approval of the Agreement. The Settling Parties shall jointly request that the Commission approve the Agreement without change, and find the Agreement to be reasonable, consistent with law and in the public interest.

Should any Proposed Decision or Alternate Proposed Decision seek a modification to this Settlement Agreement, and should any Settling Party be unwilling to accept such modification, that Settling Party shall so notify the other Settling Parties within five business days of issuance of such Proposed Decision or Alternate Proposed Decision. The Settling Parties shall thereafter promptly discuss the proposed modification and negotiate in good faith to achieve a resolution acceptable to the Settling Parties, and shall promptly seek Commission approval of the resolution so achieved. Failure to resolve such proposed modification to the satisfaction of the Settling Parties, or to obtain Commission approval of such resolution promptly thereafter, shall entitle any Settling Party to terminate its participation from this Agreement through prompt notice to the other Settling Parties.

10. COMPROMISE OF DISPUTED CLAIMS

This Settlement Agreement represents a compromise of disputed claims between the Settling Parties. The Settling Parties have reached this Settlement Agreement after taking into account the possibility that each Party may or may not prevail on any given issue. The Settling Parties assert that this Settlement Agreement is reasonable, consistent with law and in the public interest.

11. NON-PRECEDENTIAL

Consistent with Rule 12.5 of the Commission's Rules of Practice and Procedure, this Settlement Agreement is not precedential in any other pending or future proceeding before this Commission, except as expressly provided in this Settlement Agreement.

The Settling Parties expressly recognize that each Party may advocate a position that is inconsistent with this Agreement in Phase 2 of SCE's 2025 GRC, or earlier if invited to do so by the Commission in, for example, a relevant Rulemaking proceeding.

12. PREVIOUS COMMUNICATIONS

The Settlement Agreement contains the entire agreement and understanding between the Settling Parties as to the subject matter of this Settlement Agreement. In the event there is any conflict between the terms and scope of this Settlement Agreement and the terms and scope of the accompanying joint motion in support of the Settlement Agreement, the Settlement Agreement shall govern.

13. NON-WAIVER

None of the provisions of this Settlement Agreement shall be considered waived by any Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Settlement Agreement or take advantage of any of their rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

14. EFFECT OF SUBJECT HEADINGS

Subject headings in this Settlement Agreement are inserted for convenience only, and shall not be construed as interpretations of the text.

15. GOVERNING LAW

This Settlement Agreement shall be interpreted, governed and construed under the laws of the State of California, including Commission decisions, orders and rulings, as if executed and to be performed wholly within the State of California.

16. NUMBER OF ORIGINALS

This Settlement Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

Dated: February 18, 2022,

SOUTHERN CALIFORNIA EDISON COMPANY

/s/ Michael Backstrom

By: Michael Backstrom
Title: Vice President, Regulatory Policy

Dated: February 18, 2022

FEDERAL EXECUTIVE AGENCIES

/s/ Rita M. Liotta

By: Rita M. Liotta
Title: Counsel

Dated: February 18, 2022

CALIFORNIA MANUFACTURERS & TECHNOLOGY ASSOCIATION

/s/ Ronald Liebert

By: Ronald Liebert
Title: Attorney

Dated: February 18, 2022

ENERGY USERS FORUM

/s/ Robert Kehrein

By: Robert Kehrein
Title: Executive Director

Dated: February 18, 2022

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

/s/ Nora Sheriff

By: Nora Sheriff
Title: Counsel

Dated: February 18, 2022

SOLAR ENERGY INDUSTRIES ASSOCIATION

/s/ Jeanne Armstrong

By: Jeanne Armstrong
Title: Senior Regulatory Counsel

Dated: February 18, 2022

ENERGY PRODUCERS AND USERS COALITION

/s/ Nora Sheriff

By: Nora Sheriff
Title: Counsel

Dated: February 18, 2022

DIRECT ACCESS CUSTOMER COALITION

/s/ Mark Fulmer

By: Mark Fulmer
Title: Consultant to Direct Access Customer Coalition

Dated: February 18, 2022

EVGO SERVICES LLC

/s/ Sara Rafalson

By: Sara Rafalson
Title: Vice President, Market Development and Public Policy

Dated: February 18, 2022

TESLA, INC.

/s/ Kevin Auerbacher

By: Kevin Auerbacher
Title: Associate General Counsel

Appendix A

Comparison Of Party Positions On Medium and Large Power Rate Group Rate Design Issues and Settlement

Comparison of Positions
Medium and Large Power Rate Design Issues[23]

Issue	SCE	CLECA	EPUC	2021 GRC Settled Position
Option D Eligibility for TOU-GS-2 and TOU-GS-3 (<500 kW) (Base Rate)	• C&I customers with demands of >20 kW to 500 kW, but otherwise no eligibility restrictions	Not Addressed	Not Addressed	• Adopt SCE's uncontested proposal to maintain existing eligibility requirements

Option D Rate Design for TOU-GS-2 and TOU-GS-3 (<500 kW) (Base Rate)	• Propose to offer Option D as the base rate; continues to include Customer Charge, TOU Energy Charges, TRD Charges, and FRD Charge
	• Customer Charge: establish at full marginal cost-based level adjusted to recover a portion (first 50 kVA) of the FLT costs in the grid distribution demand charge
	• Generation Energy: recovered via TOU Energy Charges
	• Generation Capacity: recovered via a combination of TOU Energy Charges and TRD Charges
	• For distribution, summer on-peak TRD Charge that recovers summer on, mid- and 5% of off-peak capacity cost; winter mid-peak TRD charge that recovers all winter peak capacity cost; flat cent-per-kWh Energy Charges to recover 95% of summer off-peak capacity costs; and use of FRD Charge to recover grid-related costs
		• Rate Design should be based on cost-of-service principles using updated marginal costs. The residual amount between the marginal cost revenues and full revenue requirement for distribution and generation should be assigned on an equal percent basis to the individual rate components
		• Recommends marginal costs that increase generation demand charges somewhat relative to current levels
		• Oppose SCE's proposal to adopt a flat energy charge across all TOU periods to pick up the remaining revenue responsibility. CLECA recommends 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
			Not Addressed	• Offer Option D based on settled rate design that incorporates:
				  • Current TOU periods;
				  • Customer Charge: *See Appendix B*
				  • For distribution, summer on-peak TRD Charge that recovers summer on, mid- and 5% of off-peak capacity cost; winter mid-peak TRD charge that recovers all winter peak capacity cost; TOU Energy Charges to recover 95% of summer off-peak capacity costs; and use of FRD Charge to recover grid-related costs
				  • For generation, use SCE's proposal

Option D Eligibility for TOU-8 (>500 kW) (Base Rate)	• C&I customers with demands >500 kW with the exception of certain large water pumping and agricultural customers, but otherwise no eligibility restrictions	Not Addressed	Not Addressed	• Adopt SCE's uncontested proposal to maintain existing eligibility requirements

[23] Note that this comparison does not include the medium and large power rate design issues not covered by this agreement, namely the Real Time Pricing rate design proposals raised by the JARP and SBUA and SEIA's proposal to implement an Option S storage rate with daily demand charges.

Issue	SCE	CLECA	EPUC	2021 GRC Settled Position
Option D Rate Design for TOU-8 (>500 kW) (Base Rate)	TOU-8-SEC / TOU-8-PRI • Offer Option D that incorporates: • Current TOU periods • Customer Charge: establish at full marginal cost-based level adjusted to recover a portion (first 50 kVA) of the FLT costs in the grid distribution demand charge • For distribution, summer on-peak TRD Charge that recovers summer on, mid- and 5% of off-peak capacity cost; winter mid-peak TRD charge that recovers all winter peak capacity cost; flat cent-per-kWh Energy Charges to recover 95% of summer off-peak capacity costs; and use of FRD Charge to recover grid-related costs o Generation Energy: recovered via TOU Energy Charges o Generation Capacity: recovered via a combination of TOU Energy Charges and TRD Charges TOU-8-SUB • Offer Option D that incorporates: • Current TOU periods • Customer Charge: establish at full marginal cost-based level adjusted to recover a portion (first 50 kVA) of the FLT costs in the grid distribution demand charge • For distribution, summer on-peak TRD Charge that recovers summer on-peak capacity cost; winter mid-peak TRD charge that recovers all winter mid-peak capacity cost; FRD Charge that recovers grid-related costs and summer mid- and off-peak and winter off- and SOP-peak capacity costs; no distribution costs recovered via Energy Charges • Generation Energy: recovered via TOU Energy Charges • Generation Capacity: recovered via a combination of TOU Energy Charges and TRD Charges	• Rate Design should be based on cost-of-service principles using updated marginal costs. The residual amount between the marginal cost revenues and full revenue requirement for distribution and generation should be assigned on an equal percent basis to the individual rate components • Recommends marginal costs that increase generation demand charges somewhat relative to current levels • Oppose SCE's proposal to adopt a flat energy charge across all TOU periods to pick up the remaining revenue responsibility. CLECA recommends 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	Not Addressed	TOU-8-SEC / TOU-8-PRI • Offer Option D based on settled rate design that incorporates: • Current TOU periods; • Customer Charge: *See Appendix B* • For distribution, summer on-peak TRD Charge that recovers summer on, mid- and 5% of off-peak capacity cost; winter mid-peak TRD charge that recovers all winter peak capacity cost; TOU Energy Charges to recover 95% of summer off-peak capacity costs; and use of FRD Charge to recover grid-related costs • For generation, use SCE's proposal TOU-8-SUB • Offer SCE's proposed Option D based on rate design that incorporates: • Current TOU periods; • Customer Charge: *See Appendix B* • For distribution, summer on-peak TRD Charge that recovers summer on-peak capacity cost; winter mid-peak TRD charge that recovers all winter mid-peak capacity cost; FRD Charge that recovers grid-related costs and summer mid- and off-peak and winter off- and SOP-peak capacity costs; no distribution costs recovered via Energy Charges • For generation, use SCE's proposal

Issue	SCE	CLECA	EPUC	2021 GRC Settled Position
Option E Eligibility for TOU-GS-2 and TOU-GS-3 (<500 kW) (Base Rate)	• C&I customers with demands of >20 kW to 500 kW, but otherwise no eligibility restrictions	Not Addressed	Not Addressed	• Adopt SCE's proposal that includes no eligibility restrictions • Exempt customers with DER technologies from Standby

Option E Rate Design for TOU-GS-2 and TOU-GS-3 (<500 kW) (Base Rate)	• Continue to offer Option E
	• Customer Charge: establish at full marginal cost-based level adjusted to recover a portion (first 50 kVA) of the FLT costs in the grid distribution demand charge
	• For distribution, recover 60% of revenues (excluding the customer charge revenues) via TOU Energy Charges using PLRFs, 30% via an FRD Charge and 10% via flat Energy Charges
	• For generation, incorporate a TRD Charge set at 25% of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges
		• SCE should develop the Option E rates on the billing determinants for the Option E customer group and not on the entire customer class. To do otherwise creates a cost shift from Option E customers to other customers, which is unfair. 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, as the number of Option E customers grows, the cost shift to other customers will similarly grow.	Not Addressed	• Adopt SCE's Option E rate design that incorporates:
				  • Current TOU periods
				  • Customer Charge: *See Appendix B*
				  • For distribution, recover 60% of revenues (excluding the customer charge revenues) via TOU Energy Charges using SCE's as-proposed PLRFs, 30% via an FRD Charge and 10% via flat Energy Charges
				  • For generation, incorporate a TRD Charge set at 25% of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges
				
				• 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 twenty-five percent (25%) of revenue responsibility shortfall within the TOU-GS-3 Option E customer group. 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.
				
				• Settling Parties agree, in consultation with a working group formed of representatives of Settling Parties, SCE shall perform an attrition year DER Class Study. SCE will examine possible class definition for DER customers and perform marginal cost-based allocation and rate setting for the resulting group. The study will determine which types of customers, or service, should be categorized in a potential DER class. The study shall be conducted in the attrition years to inform SCE's 2025 GRC Phase 2 Application

<table>
<tr><th>Issue</th><th>SCE</th><th>CLECA</th><th>EPUC</th><th>2021 GRC Settled Position</th></tr>
<tr><td>Option E Eligibility for TOU-8 (>500 kW) (Base Rate)</td><td>• Propose no change to eligibility requirement</td><td>Not Addressed</td><td>Not Addressed</td><td>○ Adopt SCE's uncontested proposal on TOU-8 Option Eligibility
○ SCE to file information-only advice letters (ALs) to report on the progress toward the 250 MW cap; frequency will be every 50 MW of allocated capacity (based on signed interconnection agreement data and date) until 200 MW is reached, at which time SCE will file ALs monthly until the 250 MW cap is reached (the monthly filings will include addl data about projects still pending PTO)</td></tr>
<tr><td>Option E Rate Design for TOU-8 (>500 kW) (Base Rate)</td><td><u>TOU-8-SEC / TOU-8-PRI</u>
• Offer an Option E that incorporates:
• Current TOU periods;
• Customer Charge
• For distribution, recover 60% of revenues (excluding the customer charge revenues) via TOU Energy Charges using PLRFs, 30% via an FRD Charge and 10% via flat Energy Charges
• For generation, incorporate a TRD Charge set at 25% of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges

<u>TOU-8-SUB</u>
• Offer an Option E based on settled rate design that incorporates:
• Current TOU periods;
• Customer Charge
• For distribution, grid-related costs are recovered via an FRD charge and peak-related costs are recovered via TOU Energy Charges using PLRFs
• For generation, incorporate a TRD Charge set at 25% of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges</td><td>• SCE should develop the Option E rates on the billing determinants for the Option E customer group and not on the entire customer class. To do otherwise creates a cost shift from Option E customers to other customers, which is unfair. 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, as the number of Option E customers grows, the cost shift to other customers will similarly grow.
• Commission should direct SCE to adopt an Option E rate based on Option E customer billing determinant for each of the TOU-8 schedules once the number of Option E customers on that schedule exceeds 15 customers</td><td>Not Addressed</td><td><u>TOU-8-SEC / TOU-8-PRI</u>
• Adopt SCE Option E rate design proposal that incorporates:
• Current TOU periods;
• Customer Charge: See Appendix B
• For distribution, recover 60% of revenues (excluding the customer charge revenues) via TOU Energy Charges using SCE's as-proposed PLRFs, 30% via an FRD Charge and 10% via flat Energy Charges
• For generation, incorporate a TRD Charge set at 25% of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges

<u>TOU-8-SUB</u>
• Adopts SCE Option E rate design proposal that incorporates:
• Current TOU periods;
• Customer Charge: See Appendix B
• For distribution, grid-related costs are recovered via an FRD charge and peak-related costs are recovered via TOU Energy Charges using SCE's as-proposed PLRFs
• For generation, incorporate a TRD Charge set at 25% of the Standby Backup Demand Charge with the balance of revenues recovered via TOU Energy Charges

• Settling Parties agree, in consultation with a working group formed of representatives of Settling Parties, SCE shall perform an attrition year DER Class Study. SCE will examine possible class definition for DER customers and perform marginal cost-based allocation and rate setting for the resulting group. The study will determine which types of customers, or service, should be categorized in a potential DER class. The study shall be conducted in the attrition years to inform SCE's 2025 GRC Phase 2 Application</td></tr>
<tr><td>Real Time Pricing (RTP)</td><td>• Propose no structural change to existing RTP structure</td><td>Not Addressed</td><td>Not Addressed</td><td>• Adopt SCE's proposal</td></tr>
<tr><td>Standby Rates (Schedule S, TOU-8-S, TOU-8-RTP-S)</td><td>• No structural changes proposed for Schedule S
• Incorporate the Option D rate design described above for TOU-8-S and TOU-8-RTP-S</td><td>Not Addressed</td><td>Not Addressed</td><td>• The rate designs will be aligned with the settled changes for the Option D rates described above</td></tr>
</table>

Issue	SCE	CLECA	EPUC	2021 GRC Settled Position
Reliability Back-Up Service (TOU-8-RBU)	• Same as Current Treatment but with updated Customer Charge, TOU Energy and TRD Charge to reflect marginal-cost based changes made to Option D (as described above)	Not Addressed	Not Addressed	• Adopt SCE's uncontested proposal
EV Rates (TOU-EV-8 & TOU-EV-9)	• Proposes to maintain the current TOU-EV-8 and TOU-EV-9 rate design and revise the energy charges to reflect updated marginal costs and revenue allocations • Proposes to extend the all 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 TEF guidance can be implemented as part of an RDW in this GRC cycle or in a separate rate design proceeding as determined by the CPUC, whichever occur first.	Not Addressed	Not Addressed	• Settling Parties agree to extend the current versions of TOU-EV-8 and TOU-EV-9, beyond the five-year timeline established by D.18-05-040 for such an energy-only rate structure. Settling Parties also agree that this Settlement Agreement does not restrict the Commission from modifying TOU-EV-8 and TOU-EV-9 in any proceeding relating to transportation electrification. If the energy-only rate structures remain in effect at the time SCE files its next GRC Phase 2, then SCE shall either propose to begin the gradual introduction of demand charges consistent with the process approved in D.18-05-040 or propose rate structure updates for TOU-EV-8 and TOU-EV-9 that address how demand charges should be implemented. Adjustments to account for customers participating in the TOU-EV-8 and TOU-EV-9 rates will be made such that the revenue deficiency is contained within the individual rate class (*e.g., TOU-GS-2, TOU-GS-3, TOU-8)* in which the deficiency exists. • The energy-only rate structure shall also be offered to Direct Current Fast Charger (DCFC) to provide stability to the developing DCFC industry.
GS-APS-E	• No structural changes proposed; credit levels to remain at current level as proposed in Advice Letter 4182-E	Not Addressed	Not Addressed	• APS shall reflect the incentive budgets at the current level as shown in Appendix B.
TOU-BIP	• No structural changes proposed • The overall level of credits (*e.g.* incentives) for participants was approved in D.17-12-003. Current TOU-BIP credits are based on avoided capacity valuation approved in D.17-12-003, and updated to align with the underlying base rates (*i.e*., Option D rate). • SCE will subsequently align TOU-BIP credits with the underlying base rates once key attributes are approved in this application	Not Addressed	Not Addressed	• BIP shall reflect the incentive budgets at the current level as shown in Appendix B. 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 kWh usage in the period by the number of hours in the period. Illustrative rates are included in Appendix B.
Solar Legacy Rates (Legacy Options B and R for non-standby, Options A and B for standby)	• Maintain same eligibility, duration, rate options, and rate structures from the 2018 GRC.			• Maintain same eligibility, duration, rate options, and rate structures from the 2018 GRC.
Closing of Schedule GS-2 (Flat Rate)	• SCE plans to replace the meters on Catalina with Edison SmartConnect (ESC) meters in 2022 and migrate these customers to their applicable TOU-GS-2 rate schedule in 2024/2025. SCE shall close Schedule GS-2 upon the completion of the migration.			• Adopt SCE's uncontested proposal

Issue	SCE	CLECA	EPUC	2021 GRC Settled Position
Facilities Related Demand and Energy Charges Adjustments	• Proposes to provide an offset whereby SCE will subtract from existing distribution charges an equivalent amount to the fixed recovery charge, and recover the revenue deficiency from demand charges in those rates where demand chargers are imposed. By making this adjustment, customers in the applicable rate classes will experience a net adjustment to their demand charges with the distribution energy charges remaining flat, assuming no other changes to overall revenue or revenue allocation. This approach retains the energy charge-only structure of the fixed recovery charge approved in D.20-11-007, while satisfying EPUC's request for a distribution demand charge adjustment.		• Recommends the Commission to adopt SCE's proposed approach, design FRCs on a cent per kWh basis (energy charge) or on a dollar per kWh basis (demand charge) for distribution costs, consistent with charges of non-securitized costs	• For TOU-8 Option D rate schedules, where distribution service revenue recovery is reflected through base rates that are charged on a cents per kWh basis (energy charge), and a dollar per kW basis (demand charge), SCE shall provide an offset whereby SCE will subtract from existing distribution energy charges an amount equivalent to the Fixed Recovery Charge on a cent-per-kWh basis. The revenue imbalance of distribution base revenues created by this adjustment will be recovered through a commensurate adjustment of the non-coincident peak demand charges on a dollar-per-kW basis. By making this adjustment, customers in the applicable rate classes will experience an upward, or downward, adjustment to their demand charges with the offset in distribution energy charges, assuming no other changes to overall revenue requirement or revenue allocation to the class.

Appendix B

Illustrative Medium and Large Power Rate Group Rates

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
GS-2 (Non TOU Rate)									
Energy Charge - $/kWh									
Summer	0.09012	0.06330	0.15342	0.08465	0.06210	0.14675	-6.1%	-1.9%	-4.3%
Winter	0.06211	0.06630	0.12841	0.05521	0.06399	0.11920	-11.1%	-3.5%	-7.2%
Customer Charge - $/month	194.05		194.05	171.75		171.75	-11.5%		-11.5%
Facilities Related Demand Charge - $/kW	15.68		15.68	19.05		19.05	21.5%		21.5%
Summer Time Related Demand Charge - $/kW	0.00	15.98	15.98	0.00	13.88	13.88		-13.1%	-13.1%
Single Phase Service - $/month	(10.75)	0.00	(10.75)	(6.58)	0.00	(6.58)	-38.8%		-38.8%
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.16)		(0.16)	(0.34)		(0.34)	112.5%		112.5%
From 51 kV to 219 kV	(6.72)		(6.72)	(7.30)		(7.30)	8.6%		8.6%
220 kV and above	(11.66)		(11.66)	(15.03)		(15.03)	28.9%		28.9%
Voltage Discount, Time-Related Demand - $/kW									
From 2 kV to 50 kV	0.00	(0.25)	(0.25)	0.00	(0.37)	(0.37)		48.0%	48.0%
From 51 kV to 219 kV	0.00	(0.67)	(0.67)	0.00	(0.86)	(0.86)		28.4%	28.4%
220 kV and above	0.00	(0.68)	(0.68)	0.00	(0.87)	(0.87)		27.9%	27.9%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	(0.00054)	(0.00101)	(0.00155)	(0.00064)	(0.00104)	(0.00168)	18.5%	3.0%	8.4%
From 51 kV to 219 kV	(0.01442)	(0.00221)	(0.01663)	(0.01202)	(0.00226)	(0.01428)	-16.6%	2.3%	-14.1%
220 kV and above	(0.03488)	(0.00224)	(0.03712)	(0.02885)	(0.00229)	(0.03114)	-17.3%	2.2%	-16.1%
Bill Limiter (GS-1 to GS-2) - %	20.89%	79.11%	100.00%	20.89%	79.11%	100.00%	0.0%	0.0%	0.0%
California Climate Credit - $/kWh/Meter/Month	(0.00296)	0.00000	(0.00296)	(0.00296)	0.00000	(0.00296)	0.0%		0.0%
GS-2 (TOU Rate D)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.04711	0.09350	0.14061	0.05043	0.08975	0.14018	7.0%	-4.0%	-0.3%
Mid-peak	0.04711	0.08410	0.13121	0.04926	0.08183	0.13109	4.6%	-2.7%	-0.1%
Off-Peak	0.04711	0.05467	0.10178	0.04899	0.05417	0.10316	4.0%	-0.9%	1.4%
Winter Season									
Mid-peak	0.04711	0.07182	0.11893	0.05043	0.06251	0.11294	7.0%	-13.0%	-5.0%
Off-Peak	0.04711	0.06029	0.10740	0.04926	0.06288	0.11214	4.6%	4.3%	4.4%
Super-Off-Peak	0.04711	0.03863	0.08574	0.04860	0.03301	0.08161	3.2%	-14.5%	-4.8%
Customer Charge - $/month	194.05		194.05	171.75		171.75	-11.5%		-11.5%
Facilities Related Demand Charge - $/kW	15.68		15.68	19.05		19.05	21.5%		21.5%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	14.53	19.74	34.27	11.83	15.69	27.52	-18.6%	-20.5%	-19.7%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	5.21	4.00	9.21	2.02	4.31	6.33	-61.2%	7.7%	-31.3%
Single Phase Service - $/month	(10.75)	0.00	(10.75)	(6.58)	0.00	(6.58)	-38.8%		-38.8%
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.16)		(0.16)	(0.34)		(0.34)	112.5%		112.5%
From 51 kV to 219 kV	(6.72)		(6.72)	(7.30)		(7.30)	8.6%		8.6%
220 kV and above	(11.66)		(11.66)	(15.03)		(15.03)	28.9%		28.9%
Voltage Discount, Time-Related Demand - $/kW									
Summer Season									
From 2 kV to 50 kV	(0.13)	(0.15)	(0.28)	(0.26)	(0.42)	(0.68)	100.0%	180.0%	142.9%
From 51 kV to 219 kV	(3.61)	(0.42)	(4.03)	(4.93)	(0.97)	(5.90)	36.6%	131.0%	46.4%
220 kV and above	(8.69)	(0.42)	(9.11)	(11.83)	(0.98)	(12.81)	36.1%	133.3%	40.6%
Winter Season									
From 2 kV to 50 kV	(0.13)	(0.15)	(0.28)	(0.04)	(0.11)	(0.15)	-69.2%	-26.7%	-46.4%
From 51 kV to 219 kV	(3.61)	(0.42)	(4.03)	(0.84)	(0.27)	(1.11)	-76.7%	-35.7%	-72.5%
220 kV and above	(8.69)	(0.42)	(9.11)	(2.02)	(0.27)	(2.29)	-76.8%	-35.7%	-74.9%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	(0.00013)	(0.00088)	(0.00101)	(0.00026)	(0.00090)	(0.00116)	100.0%	2.3%	14.9%
From 51 kV to 219 kV	(0.00392)	(0.00196)	(0.00588)	(0.00488)	(0.00197)	(0.00685)	24.5%	0.5%	16.5%
220 kV and above	(0.00948)	(0.00197)	(0.01145)	(0.01174)	(0.00199)	(0.01373)	23.8%	1.0%	19.9%
TOU Rate Meter Charge - $/month									
TOU-RTEM	27.05	0.00	27.05	0.00	0.00	0.00	-100.0%		-100.0%
California Climate Credit - $/kWh/Meter/Month	(0.00296)	0.00000	(0.00296)	(0.00296)	0.00000	(0.00296)	0.0%		0.0%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
GS-2 (TOU Rate E)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.24058	0.35243	0.59301	0.32613	0.29494	0.62107	35.6%	-16.3%	4.7%
Mid-peak	0.14174	0.08410	0.22584	0.18997	0.08183	0.27180	34.0%	-2.7%	20.4%
Off-Peak	0.10364	0.05467	0.15831	0.11818	0.05417	0.17235	14.0%	-0.9%	8.9%
Winter Season									
Mid-peak	0.08130	0.11345	0.19475	0.06246	0.09751	0.15997	-23.2%	-14.1%	-17.9%
Off-Peak	0.05310	0.06029	0.11339	0.04825	0.06288	0.11113	-9.1%	4.3%	-2.0%
	0.06767	0.03863	0.10630	0.05833	0.03301	0.09134	-13.8%	-14.5%	-14.1%
Customer Charge - $/month	194.05		194.05	171.75		171.75	-11.5%		-11.5%
Facilities Related Demand Charge - $/kW	10.58	0.00	10.58	10.99	0.00	10.99	3.9%		3.9%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	4.36	4.36	0.00	4.08	4.08		-6.4%	-6.4%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.00	0.84	0.84	0.00	1.64	1.64		95.2%	95.2%
Single Phase Service - $/month	(10.75)	0.00	(10.75)	(6.58)	0.00	(6.58)	-38.8%		-38.8%
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.09)	0.00	(0.09)	(0.16)	0.00	(0.16)	77.8%		77.8%
From 51 kV to 219 kV	(3.78)	0.00	(3.78)	(3.39)	0.00	(3.39)	-10.3%		-10.3%
220 kV and above	(6.56)	0.00	(6.56)	(6.97)	0.00	(6.97)	6.3%		6.3%
Voltage Discount, Time Related Demand - $/kW									
Summer Season									
From 2 kV to 50 kV	0.00	(0.03)	(0.03)	0.00	(0.16)	(0.16)		433.3%	433.3%
From 51 kV to 219 kV	0.00	(0.09)	(0.09)	0.00	(0.37)	(0.37)		311.1%	311.1%
220 kV and above	0.00	(0.09)	(0.09)	0.00	(0.37)	(0.37)		311.1%	311.1%
Winter Season									
From 2 kV to 50 kV	0.00	(0.03)	(0.03)	0.00	(0.04)	(0.04)		33.3%	33.3%
From 51 kV to 219 kV	0.00	(0.09)	(0.09)	0.00	(0.10)	(0.10)		11.1%	11.1%
220 kV and above	0.00	(0.09)	(0.09)	0.00	(0.10)	(0.10)		11.1%	11.1%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	(0.00075)	(0.00123)	(0.00198)	(0.00126)	(0.00132)	(0.00258)	68.0%	7.3%	30.3%
From 51 kV to 219 kV	(0.02464)	(0.00295)	(0.02759)	(0.02551)	(0.00296)	(0.02847)	3.5%	0.3%	3.2%
220 kV and above	(0.05257)	(0.00296)	(0.05553)	(0.05662)	(0.00299)	(0.05961)	7.7%	1.0%	7.3%
TOU Rate Meter Charge - $/month									
TOU-RTEM	27.05	0.00	27.05	0.00	0.00	0.00	-100.0%		-100.0%
California Climate Credit - $/kWh/Meter/Month	(0.00296)	0.00000	(0.00296)	(0.00296)	0.00000	(0.00296)	0.0%		0.0%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-GS-2-CPP									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.04711	0.09350	0.14061	0.05043	0.08975	0.14018	7.0%	-4.0%	-0.3%
Mid-peak	0.04711	0.08410	0.13121	0.04926	0.08183	0.13109	4.6%	-2.7%	-0.1%
Off-Peak	0.04711	0.05467	0.10178	0.04899	0.05417	0.10316	4.0%	-0.9%	1.4%
Winter Season									
Mid-peak	0.04711	0.07182	0.11893	0.05043	0.06251	0.11294	7.0%	-13.0%	-5.0%
Off-Peak	0.04711	0.06029	0.10740	0.04926	0.06288	0.11214	4.6%	4.3%	4.4%
Super-Off-Peak	0.04711	0.03863	0.08574	0.04860	0.03301	0.08161	3.2%	-14.5%	-4.8%
Customer Charge - $/month	194.05		194.05	171.75		171.75	-11.5%		-11.5%
Single Phase Service - $/month	(10.75)		(10.75)	(6.58)		(6.58)	-38.8%		-38.8%
Facilities Related Demand Charge - $/kW	15.68	0.00	15.68	19.05	0.00	19.05	21.5%		21.5%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	14.53	19.74	34.27	11.83	15.69	27.52	-18.6%	-20.5%	-19.7%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	5.21	4.00	9.21	2.02	4.31	6.33	-61.2%	7.7%	-31.3%
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.16)	0.00	(0.16)	(0.34)	0.00	(0.34)	112.5%		112.5%
Above 50 kV but below 220 kV	(6.72)	0.00	(6.72)	(7.30)	0.00	(7.30)	8.6%		8.6%
At 220 kV	(11.66)	0.00	(11.66)	(15.03)	0.00	(15.03)	28.9%		28.9%
Voltage Discount, Time-Related Demand - $/kW									
Summer Season									
From 2 kV to 50 kV	(0.13)	(0.15)	(0.28)	(0.26)	(0.42)	(0.68)	100.0%	180.0%	142.9%
Above 50 kV but below 220 kV	(3.61)	(0.42)	(4.03)	(4.93)	(0.97)	(5.90)	36.6%	131.0%	46.4%
At 220 kV	(8.69)	(0.42)	(9.11)	(11.83)	(0.98)	(12.81)	36.1%	133.3%	40.6%
Winter Season									
From 2 kV to 50 kV	(0.13)	(0.15)	(0.28)	(0.04)	(0.11)	(0.15)	-69.2%	-26.7%	-46.4%
Above 50 kV but below 220 kV	(3.61)	(0.42)	(4.03)	(0.84)	(0.27)	(1.11)	-76.7%	-35.7%	-72.5%
At 220 kV	(8.69)	(0.42)	(9.11)	(2.02)	(0.27)	(2.29)	-76.8%	-35.7%	-74.9%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	(0.00013)	(0.00088)	(0.00101)	(0.00026)	(0.00090)	(0.00116)	100.0%	2.3%	14.9%
Above 50 kV but below 220 kV	(0.00392)	(0.00196)	(0.00588)	(0.00488)	(0.00197)	(0.00685)	24.5%	0.5%	16.5%
At 220 kV	(0.00948)	(0.00197)	(0.01145)	(0.01174)	(0.00199)	(0.01373)	23.8%	1.0%	19.9%
TOU Rate Meter Charge - $/month									
TOU-RTEM	27.05	0.00	27.05	0.00	0.00	0.00	-100.0%		-100.0%
CPP Event Energy Charge - $/kWh	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer CPP Non-Event Credit									
On-Peak Demand Credit - $/kW	0.00	(6.85)	(6.85)	0.00	(6.85)	(6.85)		0.0%	0.0%
California Climate Credit - $/kWh/Meter/Month	(0.00296)	0.00000	(0.00296)	(0.00296)	0.00000	(0.00296)	0.0%		0.0%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-GS-2-RTP									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.04711	Variable*	Variable*	0.05043	Variable*	Variable*	7.0%		
Mid-peak	0.04711	Variable*		0.04926	Variable*	Variable*	4.6%		
Off-Peak	0.04711	Variable*		0.04899	Variable*	Variable*	4.0%		
Winter Season									
Mid-peak	0.04711	Variable*		0.05043	Variable*	Variable*	7.0%		
Off-Peak	0.04711	Variable*		0.04926	Variable*	Variable*	4.6%		
Super-Off-Peak	0.04711	Variable*		0.04860	Variable*	Variable*	3.2%		
Customer Charge - $/month	194.05		194.05	171.75		171.75	-11.5%		-11.5%
Single Phase Service - $/month	(10.75)		(10.75)	(6.58)		(6.58)	-38.8%		-38.8%
Facilities Related Demand Charge - $/kW	15.68		15.68	19.05		19.05	21.5%		21.5%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	14.53	0.00	14.53	11.83	0.00	11.83	-18.6%		-18.6%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	5.21	0.00	5.21	2.02	0.00	2.02	-61.2%		-61.2%
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.16)		(0.16)	(0.34)		(0.34)	112.5%		112.5%
Above 50 kV but below 220 kV	(6.72)		(6.72)	(7.30)		(7.30)	8.6%		8.6%
At 220 kV	(11.66)		(11.66)	(15.03)		(15.03)	28.9%		28.9%
Voltage Discount, Time-Related Demand - $/kW									
Summer Season									
From 2 kV to 50 kV	(0.13)		(0.13)	(0.26)		(0.26)	100.0%		100.0%
Above 50 kV but below 220 kV	(3.61)		(3.61)	(4.93)		(4.93)	36.6%		36.6%
At 220 kV	(8.69)		(8.69)	(11.83)		(11.83)	36.1%		36.1%
Winter Season									
From 2 kV to 50 kV	(0.13)		(0.13)	(0.04)		(0.04)	-69.2%		-69.2%
Above 50 kV but below 220 kV	(3.61)		(3.61)	(0.84)		(0.84)	-76.7%		-76.7%
At 220 kV	(8.69)		(8.69)	(2.02)		(2.02)	-76.8%		-76.8%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	(0.00013)	(0.00123)	(0.00136)	(0.00026)	(0.00132)	(0.00158)	100.0%	7.3%	16.2%
Above 50 kV but below 220 kV	(0.00392)	(0.00295)	(0.00687)	(0.00488)	(0.00296)	(0.00784)	24.5%	0.3%	14.1%
At 220 kV	(0.00948)	(0.00296)	(0.01244)	(0.01174)	(0.00299)	(0.01473)	23.8%	1.0%	18.4%
TOU Rate Meter Charge - $/month									
TOU-RTEM	27.05		27.05	0.00		0.00	-100.0%		-100.0%
California Climate Credit - $/kWh/Meter/Month	(0.00296)	0.00000	(0.00296)	(0.00296)	0.00000	(0.00296)	0.0%		0.0%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
GS-2 (TOU Rate B) - GF									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.03763	0.06746	0.10509	0.03752	0.06632	0.10384	-0.3%	-1.7%	-1.2%
Mid-peak	0.03763	0.06324	0.10087	0.03752	0.06204	0.09956	-0.3%	-1.9%	-1.3%
Off-Peak	0.03763	0.06072	0.09835	0.03752	0.05968	0.09720	-0.3%	-1.7%	-1.2%
Winter Season									
Mid-peak	0.03763	0.08195	0.11958	0.03752	0.08018	0.11770	-0.3%	-2.2%	-1.6%
Off-Peak	0.03763	0.05122	0.08885	0.03752	0.04811	0.08563	-0.3%	-6.1%	-3.6%
Customer Charge - $/month	194.05		194.05	171.75		171.75	-11.5%		-11.5%
Facilities Related Demand Charge - $/kW	25.89		25.89	27.27		27.27	5.3%		5.3%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	13.86	13.86	0.00	10.88	10.88		-21.5%	-21.5%
Mid-Peak	0.00	4.60	4.60	0.00	3.66	3.66		-20.4%	-20.4%
Single Phase Service - $/month	(10.75)	0.00	(10.75)	(6.58)	0.00	(6.58)	-38.8%		-38.8%
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.31)		(0.31)	(0.63)		(0.63)	103.2%		103.2%
From 51 kV to 219 kV	(10.95)		(10.95)	(12.86)		(12.86)	17.4%		17.4%
220 kV and above	(21.87)		(21.87)	(23.25)		(23.25)	6.3%		6.3%
Voltage Discount, Time-Related Demand - $/kW									
From 2 kV to 50 kV	0.00	(0.19)	(0.19)	0.00	(0.51)	(0.51)		168.4%	168.4%
From 51 kV to 219 kV	0.00	(0.52)	(0.52)	0.00	(1.18)	(1.18)		126.9%	126.9%
220 kV and above	0.00	(0.52)	(0.52)	0.00	(1.19)	(1.19)		128.8%	128.8%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	0.00000	(0.00088)	(0.00088)	0.00000	(0.00090)	(0.00090)		2.3%	2.3%
From 51 kV to 219 kV	0.00000	(0.00196)	(0.00196)	0.00000	(0.00197)	(0.00197)		0.5%	0.5%
220 kV and above	0.00000	(0.00197)	(0.00197)	0.00000	(0.00199)	(0.00199)		1.0%	1.0%
TOU Rate Meter Charge - $/month									
TOU-RTEM	27.05	0.00	27.05	0.00	0.00	0.00	-100.0%		-100.0%
California Climate Credit - $/kWh/Meter/Month	(0.00296)	0.00000	(0.00296)	(0.00296)	0.00000	(0.00296)	0.0%		0.0%
GS-2 (TOU Rate R) - GF									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.19861	0.23780	0.43641	0.21241	0.20998	0.42239	6.9%	-11.7%	-3.2%
Mid-peak	0.09971	0.11092	0.21063	0.13014	0.10215	0.23229	30.5%	-7.9%	10.3%
Off-Peak	0.05642	0.06072	0.11714	0.07114	0.05968	0.13082	26.1%	-1.7%	11.7%
Winter Season									
Mid-peak	0.06245	0.08195	0.14440	0.05423	0.08018	0.13441	-13.2%	-2.2%	-6.9%
Off-Peak	0.04475	0.05122	0.09597	0.04157	0.04811	0.08968	-7.1%	-6.1%	-6.6%
Customer Charge - $/month	194.05		194.05	171.75		171.75	-11.5%		-11.5%
Facilities Related Demand Charge - $/kW	15.49	0.00	15.49	16.21	0.00	16.21	4.6%		4.6%
Single Phase Service - $/month	(10.75)	0.00	(10.75)	(6.58)	0.00	(6.58)	-38.8%		-38.8%
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.16)	0.00	(0.16)	(0.33)	0.00	(0.33)	106.3%		106.3%
From 51 kV to 219 kV	(5.74)	0.00	(5.74)	(6.74)	0.00	(6.74)	17.4%		17.4%
220 kV and above	(11.47)	0.00	(11.47)	(12.19)	0.00	(12.19)	6.3%		6.3%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	(0.00051)	(0.00133)	(0.00184)	(0.00105)	(0.00216)	(0.00321)	105.9%	62.4%	74.5%
From 51 kV to 219 kV	(0.01790)	(0.00323)	(0.02113)	(0.02128)	(0.00487)	(0.02615)	18.9%	50.8%	23.8%
220 kV and above	(0.03576)	(0.00324)	(0.03900)	(0.03847)	(0.00492)	(0.04339)	7.6%	51.9%	11.3%
TOU Rate Meter Charge - $/month									
TOU-RTEM	27.05	0.00	27.05	0.00	0.00	0.00	-100.0%		-100.0%
California Climate Credit - $/kWh/Meter/Month	(0.00296)	0.00000	(0.00296)	(0.00296)	0.00000	(0.00296)	0.0%		0.0%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
GS-APS-E (Schedules: GS-2, TOU-GS-3, or TOU-8)									
Air Conditioning Cycling Credit - $/ton/summer season month									
30% Cycling	(0.58)	0.00	(0.58)	(0.58)	0.00	(0.58)	0.0%		0.0%
40% Cycling	0.00	0.00	0.00	0.00	0.00	0.00			
50% Cycling	(2.90)	0.00	(2.90)	(2.90)	0.00	(2.90)	0.0%		0.0%
100% Cycling	(8.24)	0.00	(8.24)	(8.24)	0.00	(8.24)	0.0%		0.0%
TOU-EV-8									
Energy Charge - $/kWh									
Summer Season On-Peak	0.27589	0.31932	0.59521	0.22374	0.27536	0.49910	-18.9%	-13.8%	-16.1%
Mid-Peak	0.27589	0.08410	0.35999	0.22374	0.08183	0.30557	-18.9%	-2.7%	-15.1%
Off-Peak	0.09112	0.06696	0.15808	0.12003	0.06449	0.18452	31.7%	-3.7%	16.7%
Winter Season On-Peak	0.27589	0.12457	0.40046	0.22374	0.11898	0.34272	-18.9%	-4.5%	-14.4%
Mid-Peak	0.09112	0.07665	0.16777	0.12003	0.07574	0.19577	31.7%	-1.2%	16.7%
Off-Peak	0.05909	0.03863	0.09772	0.07225	0.03301	0.10526	22.3%	-14.5%	7.7%
Customer Charge - $/meter/month	194.05		194.05	171.75		171.75	-11.5%		-11.5%
Facilities Related									
Demand Charge - $/kW	0.00			0.00		0.00			
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	0.00	0.00		0.00	0.00	0.00			
From 51 kV to 219 kV	0.00	0.00		0.00	0.00	0.00			
220 kV and above	0.00	0.00		0.00	0.00	0.00			
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	(0.00106)	(0.00133)	(0.00239)	(0.00221)	(0.00216)	(0.00437)	108.5%	62.4%	82.8%
From 51 kV to 219 kV	(0.03764)	(0.00323)	(0.04087)	(0.04474)	(0.00487)	(0.04961)	18.9%	50.8%	21.4%
220 kV and above	(0.07513)	(0.00324)	(0.07837)	(0.09873)	(0.00492)	(0.10365)	31.4%	51.9%	32.3%
Power Factor Adjustment - $/kVA									
Greater than 50 kV	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
50 kV or less	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
California Climate Credit - $/kWh/Meter/Month	(0.00296)	0.00000	(0.00296)	(0.00296)	0.00000	(0.00296)	0.0%		0.0%
TOU-GS-3 (Rate D)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.04506	0.08771	0.13277	0.05024	0.08767	0.13791	11.5%	0.0%	3.9%
Mid-peak	0.04506	0.07887	0.12393	0.04904	0.07994	0.12898	8.8%	1.4%	4.1%
Off-Peak	0.04506	0.05185	0.09691	0.04878	0.05185	0.10063	8.3%	0.0%	3.8%
Winter Season									
Mid-peak	0.04506	0.06810	0.11316	0.05024	0.05983	0.11007	11.5%	-12.1%	-2.7%
Off-Peak	0.04506	0.05716	0.10222	0.04904	0.06020	0.10924	8.8%	5.3%	6.9%
Super-Off-Peak	0.04506	0.03667	0.08173	0.04836	0.03162	0.07998	7.3%	-13.8%	-2.1%
Customer Charge - $/month	469.70	0.00	469.70	505.50	0.00	505.50	7.6%		7.6%
Facilities Related									
Demand Charge - $/kW	16.94	0.00	16.94	17.92	0.00	17.92	5.8%		5.8%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	15.26	18.95	34.21	14.68	17.05	31.73	-3.8%	-10.0%	-7.2%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	5.17	3.44	8.61	2.61	5.52	8.13	-49.5%	60.5%	-5.6%
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.18)	0.00	(0.18)	(0.28)	0.00	(0.28)	55.6%		55.6%
From 51 kV to 219 kV	(7.68)	0.00	(7.68)	(6.13)	0.00	(6.13)	-20.2%		-20.2%
220 kV and above	(12.56)	0.00	(12.56)	(13.54)	0.00	(13.54)	7.8%		7.8%
Voltage Discount, Time-Related Demand - $/kW									
Summer Season									
From 2 kV to 50 kV	(0.13)	(0.15)	(0.28)	(0.29)	(0.47)	(0.76)	123.1%	213.3%	171.4%
From 51 kV to 219 kV	(3.71)	(0.40)	(4.11)	(5.48)	(1.10)	(6.58)	47.7%	175.0%	60.1%
220 kV and above	(8.80)	(0.40)	(9.20)	(14.68)	(1.11)	(15.79)	66.8%	177.5%	71.6%
Winter Season									
From 2 kV to 50 kV	(0.13)	(0.15)	(0.28)	(0.05)	(0.15)	(0.20)	-61.5%	0.0%	-28.6%
From 51 kV to 219 kV	(3.71)	(0.40)	(4.11)	(0.98)	(0.36)	(1.34)	-73.6%	-10.0%	-67.4%
220 kV and above	(8.80)	(0.40)	(9.20)	(2.61)	(0.36)	(2.97)	-70.3%	-10.0%	-67.7%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	(0.00013)	(0.00088)	(0.00101)	(0.00024)	(0.00091)	(0.00115)	84.6%	3.4%	13.9%
From 51 kV to 219 kV	(0.00344)	(0.00194)	(0.00538)	(0.00448)	(0.00197)	(0.00645)	30.2%	1.5%	19.9%
220 kV and above	(0.00822)	(0.00195)	(0.01017)	(0.01213)	(0.00199)	(0.01412)	47.6%	2.1%	38.8%
Power Factor Adjustment - $/kVA									
Greater than 50 kV	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
50 kV or less	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-GS-3 (Rate E)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.22990	0.31280	0.54270	0.32834	0.28722	0.61556	42.8%	-8.2%	13.4%
Mid-peak	0.14330	0.07887	0.22217	0.18979	0.07994	0.26973	32.4%	1.4%	21.4%
Off-Peak	0.09607	0.05185	0.14792	0.11328	0.05185	0.16513	17.9%	0.0%	11.6%
Winter Season									
Mid-peak	0.07655	0.10029	0.17684	0.06238	0.10054	0.16292	-18.5%	0.2%	-7.9%
Off-Peak	0.05005	0.05716	0.10721	0.04731	0.06020	0.10751	-5.5%	5.3%	0.3%
Super-Off-Peak	0.06355	0.03667	0.10022	0.05784	0.03162	0.08946	-9.0%	-13.8%	-10.7%
Customer Charge - $/month	469.70	0.00	469.70	505.50	0.00	505.50	7.6%		7.6%
Facilities Related									
Demand Charge - $/kW	11.26	0.00	11.26	11.48	0.00	11.48	2.0%		2.0%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	4.18	4.18	0.00	4.44	4.44		6.2%	6.2%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.00	0.73	0.73	0.00	2.10	2.10		187.7%	187.7%
Off-Peak	0.00	0.00		0.00	0.00	0.00			
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.10)	0.00	(0.10)	(0.15)	0.00	(0.15)	50.0%		50.0%
From 51 kV to 219 kV	(4.21)	0.00	(4.21)	(3.22)	0.00	(3.22)	-23.5%		-23.5%
220 kV and above	(6.88)	0.00	(6.88)	(7.10)	0.00	(7.10)	3.2%		3.2%
Voltage Discount, Time Related Demand - $/kW									
Summer Season									
From 2 kV to 50 kV	0.00	(0.03)	(0.03)	0.00	(0.18)	(0.18)		500.0%	500.0%
From 51 kV to 219 kV	0.00	(0.09)	(0.09)	0.00	(0.42)	(0.42)		366.7%	366.7%
220 kV and above	0.00	(0.09)	(0.09)	0.00	(0.42)	(0.42)		366.7%	366.7%
Winter Season									
From 2 kV to 50 kV	0.00	(0.03)	(0.03)	0.00	(0.06)	(0.06)		100.0%	100.0%
From 51 kV to 219 kV	0.00	(0.09)	(0.09)	0.00	(0.14)	(0.14)		55.6%	55.6%
220 kV and above	0.00	(0.09)	(0.09)	0.00	(0.14)	(0.14)		55.6%	55.6%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	(0.00069)	(0.00118)	(0.00187)	(0.00097)	(0.00181)	(0.00278)	40.6%	53.4%	48.7%
From 51 kV to 219 kV	(0.02265)	(0.00274)	(0.02539)	(0.02042)	(0.00408)	(0.02450)	-9.8%	48.9%	-3.5%
220 kV and above	(0.04636)	(0.00275)	(0.04911)	(0.05080)	(0.00412)	(0.05492)	9.6%	49.8%	11.8%
Power Factor Adjustment - $/kVA									
Greater than 50 kV	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
50 kV or less	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-GS-3-CPP									
Critical Peak Pricing									
Time-of-Use Pricing Rate Energy Charge - $/kWh									
Summer Season									
On-Peak	0.04506	0.08771	0.13277	0.05024	0.08767	0.13791	11.5%	0.0%	3.9%
Mid-peak	0.04506	0.07887	0.12393	0.04904	0.07994	0.12898	8.8%	1.4%	4.1%
Off-Peak	0.04506	0.05185	0.09691	0.04878	0.05185	0.10063	8.3%	0.0%	3.8%
Winter Season									
Mid-peak	0.04506	0.06810	0.11316	0.05024	0.05983	0.11007	11.5%	-12.1%	-2.7%
Off-Peak	0.04506	0.05716	0.10222	0.04904	0.06020	0.10924	8.8%	5.3%	6.9%
Super-Off-Peak	0.04506	0.03667	0.08173	0.04836	0.03162	0.07998	7.3%	-13.8%	-2.1%
Customer Charge - $/month	469.70	0.00	469.70	505.50	0.00	505.50	7.6%		7.6%
Facilities Related Demand Charge - $/kW	16.94	0.00	16.94	17.92	0.00	17.92	5.8%		5.8%
Time Related Demand Charge - $/kW									
Summer Season On-Peak	15.26	18.95	34.21	14.68	17.05	31.73	-3.8%	-10.0%	-7.2%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season Mid-Peak	5.17	3.44	8.61	2.61	5.52	8.13	-49.5%	60.5%	-5.6%
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.18)	0.00	(0.18)	(0.28)	0.00	(0.28)	55.6%		55.6%
From 51 kV to 219 kV	(7.68)	0.00	(7.68)	(6.13)	0.00	(6.13)	-20.2%		-20.2%
220 kV and above	(12.56)	0.00	(12.56)	(13.54)	0.00	(13.54)	7.8%		7.8%
Voltage Discount, Time-Related Demand - $/kW									
Summer Season									
From 2 kV to 50 kV	(0.13)	(0.15)	(0.28)	(0.29)	(0.47)	(0.76)	123.1%	213.3%	171.4%
From 51 kV to 219 kV	(3.71)	(0.40)	(4.11)	(5.48)	(1.10)	(6.58)	47.7%	175.0%	60.1%
220 kV and above	(8.80)	(0.40)	(9.20)	(14.68)	(1.11)	(15.79)	66.8%	177.5%	71.6%
Winter Season									
From 2 kV to 50 kV	(0.13)	(0.15)	(0.28)	(0.05)	(0.15)	(0.20)	-61.5%	0.0%	-28.6%
From 51 kV to 219 kV	(3.71)	(0.40)	(4.11)	(0.98)	(0.36)	(1.34)	-73.6%	-10.0%	-67.4%
220 kV and above	(8.80)	(0.40)	(9.20)	(2.61)	(0.36)	(2.97)	-70.3%	-10.0%	-67.7%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	(0.00013)	(0.00088)	(0.00101)	(0.00024)	(0.00091)	(0.00115)	84.6%	3.4%	13.9%
From 51 kV to 219 kV	(0.00344)	(0.00194)	(0.00538)	(0.00448)	(0.00197)	(0.00645)	30.2%	1.5%	19.9%
220 kV and above	(0.00822)	(0.00195)	(0.01017)	(0.01213)	(0.00199)	(0.01412)	47.6%	2.1%	38.8%
Power Factor Adjustment - $/kVA									
Greater than 50 kV	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
50 kV or less	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
CPP Event Energy Charge - $/kWh	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer CPP Non-Event Credit									
On-Peak Demand Credit - $/kW	0.00	(7.55)	(7.55)	0.00	(7.55)	(7.55)		0.0%	0.0%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-GS-3-RTP									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.04506	Variable*	Variable*	0.05024	Variable*	Variable*	11.5%		
Mid-peak	0.04506	Variable*		0.04904	Variable*	Variable*	8.8%		
Off-Peak	0.04506	Variable*		0.04878	Variable*	Variable*	8.3%		
Winter Season									
Mid-peak	0.04506	Variable*		0.05024	Variable*	Variable*	11.5%		
Off-Peak	0.04506	Variable*		0.04904	Variable*	Variable*	8.8%		
Super-Off-Peak	0.04506	Variable*		0.04836	Variable*	Variable*	7.3%		
Customer Charge - $/month	469.70	0.00	469.70	505.50	0.00	505.50	7.6%		7.6%
Facilities Related									
Demand Charge - $/kW	16.94	0.00	16.94	17.92	0.00	17.92	5.8%		5.8%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	15.26	0.00	15.26	14.68	0.00	14.68	-3.8%		-3.8%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Winter Season									
Mid-Peak	5.17	0.00	5.17	2.61	0.00	2.61	-49.5%		-49.5%
Off-Peak	0.00	0.00		0.00	0.00	0.00			
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	(0.18)	0.00	(0.18)	(0.28)	0.00	(0.28)	55.6%		55.6%
Above 50 kV but below 220 kV	(7.68)	0.00	(7.68)	(6.13)	0.00	(6.13)	-20.2%		-20.2%
At 220 kV	(12.56)	0.00	(12.56)	(13.54)	0.00	(13.54)	7.8%		7.8%
Voltage Discount, Time-Related Demand - $/kW									
Summer Season									
From 2 kV to 50 kV	(0.13)	0.00	(0.13)	(0.29)	0.00	(0.29)	123.1%		123.1%
From 51 kV to 219 kV	(3.71)	0.00	(3.71)	(5.48)	0.00	(5.48)	47.7%		47.7%
220 kV and above	(8.80)	0.00	(8.80)	(14.68)	0.00	(14.68)	66.8%		66.8%
Winter Season									
From 2 kV to 50 kV	(0.13)	0.00	(0.13)	(0.05)	0.00	(0.05)	-61.5%		-61.5%
From 51 kV to 219 kV	(3.71)	0.00	(3.71)	(0.98)	0.00	(0.98)	-73.6%		-73.6%
220 kV and above	(8.80)	0.00	(8.80)	(2.61)	0.00	(2.61)	-70.3%		-70.3%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	(0.00013)	(0.00118)	(0.00131)	(0.00024)	(0.00181)	(0.00205)	84.6%	53.4%	56.5%
From 51 kV to 219 kV	(0.00344)	(0.00274)	(0.00618)	(0.00448)	(0.00408)	(0.00856)	30.2%	48.9%	38.5%
220 kV and above	(0.00822)	(0.00275)	(0.01097)	(0.01213)	(0.00412)	(0.01625)	47.6%	49.8%	48.1%
Power Factor Adjustment - $/kVA									
Greater than 50 kV	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
50 kV or less	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-GS-3 (Rate B) - GF									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.03684	0.06328	0.10012	0.03691	0.06343	0.10034	0.2%	0.2%	0.2%
Mid-peak	0.03684	0.05924	0.09608	0.03691	0.05923	0.09614	0.2%	0.0%	0.1%
Off-Peak	0.03684	0.05696	0.09380	0.03691	0.05709	0.09400	0.2%	0.2%	0.2%
Winter Season									
Mid-peak	0.03684	0.07198	0.10882	0.03691	0.08105	0.11796	0.2%	12.6%	8.4%
Off-Peak	0.03684	0.04849	0.08533	0.03691	0.04632	0.08323	0.2%	-4.5%	-2.5%
Customer Charge - $/month	469.70	0.00	469.70	505.50	0.00	505.50	7.6%		7.6%
Facilities Related									
Demand Charge - $/kW	27.31	0.00	27.31	28.06	0.00	28.06	2.7%		2.7%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	12.65	12.65	0.00	11.43	11.43		-9.6%	-9.6%
Mid-Peak	0.00	4.21	4.21	0.00	3.82	3.82		-9.3%	-9.3%
Winter Season									
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Off-Peak	0.00	0.00		0.00	0.00	0.00			
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	-0.34	0.00	(0.34)	-0.61	0.00	(0.61)	79.4%		79.4%
From 51 kV to 219 kV	-12.01	0.00	(12.01)	-12.31	0.00	(12.31)	2.5%		2.5%
220 kV and above	-22.93	0.00	(22.93)	-23.68	0.00	(23.68)	3.3%		3.3%
Voltage Discount, Time-Related Demand - $/kW									
From 2 kV to 50 kV	0.00	-0.18	(0.18)	0.00	-0.57	(0.57)		216.7%	216.7%
From 51 kV to 219 kV	0.00	-0.48	(0.48)	0.00	-1.33	(1.33)		177.1%	177.1%
220 kV and above	0.00	-0.48	(0.48)	0.00	-1.34	(1.34)		179.2%	179.2%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	0.00000	-0.00088	(0.00088)	0.00000	-0.00091	(0.00091)		3.4%	3.4%
From 51 kV to 219 kV	0.00000	-0.00194	(0.00194)	0.00000	-0.00197	(0.00197)		1.5%	1.5%
220 kV and above	0.00000	-0.00195	(0.00195)	0.00000	-0.00199	(0.00199)		2.1%	2.1%
Power Factor Adjustment - $/kVA									
Greater than 50 kV	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
50 kV or less	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
TOU-GS-3 (Rate R) - GF									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.18836	0.21071	0.39907	0.22362	0.20409	0.42771	18.7%	-3.1%	7.2%
Mid-peak	0.09197	0.09833	0.19030	0.12902	0.09603	0.22505	40.3%	-2.3%	18.3%
Off-Peak	0.05305	0.05696	0.11001	0.06908	0.05709	0.12617	30.2%	0.2%	14.7%
Winter Season									
Mid-peak	0.05799	0.07198	0.12997	0.05334	0.08105	0.13439	-8.0%	12.6%	3.4%
Off-Peak	0.04276	0.04849	0.09125	0.04072	0.04632	0.08704	-4.8%	-4.5%	-4.6%
Customer Charge - $/month	469.70	0.00	469.70	505.50	0.00	505.50	7.6%		7.6%
Facilities Related									
Demand Charge - $/kW	16.73	0.00	16.73	17.13	0.00	17.13	2.4%		2.4%
Voltage Discount, Facilities Related Demand - $/kW									
From 2 kV to 50 kV	-0.18	0.00	(0.18)	-0.33	0.00	(0.33)	83.3%		83.3%
From 51 kV to 219 kV	-6.47	0.00	(6.47)	-6.63	0.00	(6.63)	2.5%		2.5%
220 kV and above	-12.35	0.00	(12.35)	-12.75	0.00	(12.75)	3.2%		3.2%
Voltage Discount, Energy - $/kWh									
From 2 kV to 50 kV	-0.00045	-0.00127	(0.00172)	-0.00082	-0.00212	(0.00294)	82.2%	66.9%	70.9%
From 51 kV to 219 kV	-0.01609	-0.00297	(0.01906)	-0.01659	-0.00479	(0.02138)	3.1%	61.3%	12.2%
220 kV and above	-0.03071	-0.00298	(0.03369)	-0.03192	-0.00484	(0.03676)	3.9%	62.4%	9.1%
Power Factor Adjustment - $/kVA									
Greater than 50 kV	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
50 kV or less	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-EV-9 (Below 2kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.23426	0.28972	0.52398	0.19123	0.23435	0.42558	-18.4%	-19.1%	-18.8%
Off-Peak	0.23426	0.07311	0.30737	0.19123	0.07645	0.26768	-18.4%	4.6%	-12.9%
SOff-Peak	0.07627	0.05665	0.13292	0.09587	0.05903	0.15490	25.7%	4.2%	16.5%
Winter Season									
On-Peak	0.23426	0.10816	0.34242	0.19123	0.11386	0.30509	-18.4%	5.3%	-10.9%
Off-Peak	0.07627	0.06237	0.13864	0.09587	0.06772	0.16359	25.7%	8.6%	18.0%
SOff-Peak	0.05378	0.03288	0.08666	0.06575	0.03118	0.09693	22.3%	-5.2%	11.9%
Customer Charge - $/month	701.42		701.42	319.75		319.75	-54.4%		-54.4%
Facilities Related Demand Charge - $/kW	0.00			0.00		0.00			
Power Factor Adjustment - $/kVA	0.60		0.60	0.52		0.52	-13.3%		-13.3%
TOU-EV-9 (From 2 kV to 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.20847	0.27229	0.48076	0.17126	0.22581	0.39707	-17.8%	-17.1%	-17.4%
Off-Peak	0.20847	0.06896	0.27743	0.17126	0.07299	0.24425	-17.8%	5.8%	-12.0%
SOff-Peak	0.06896	0.05305	0.12201	0.08480	0.05487	0.13967	23.0%	3.4%	14.5%
Winter Season									
On-Peak	0.20847	0.10298	0.31145	0.17126	0.11327	0.28453	-17.8%	10.0%	-8.6%
Off-Peak	0.06896	0.05763	0.12659	0.08480	0.06269	0.14749	23.0%	8.8%	16.5%
SOff-Peak	0.05088	0.03111	0.08199	0.06134	0.02921	0.09055	20.6%	-6.1%	10.4%
Customer Charge - $/month	373.12		373.12	304.00		304.00	-18.5%		-18.5%
Facilities Related Demand Charge - $/kW	0.00			0.00		0.00			
Power Factor Adjustment - $/kVA	0.60		0.60	0.52		0.52	-13.3%		-13.3%
TOU-EV-9 (Above 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.08032	0.24769	0.32801	0.07503	0.20204	0.27707	-6.6%	-18.4%	-15.5%
Off-Peak	0.08032	0.06462	0.14494	0.07503	0.06735	0.14238	-6.6%	4.2%	-1.8%
SOff-Peak	0.04266	0.05011	0.09277	0.04650	0.05043	0.09693	9.0%	0.6%	4.5%
Winter Season									
On-Peak	0.08032	0.10021	0.18053	0.07503	0.09502	0.17005	-6.6%	-5.2%	-5.8%
Off-Peak	0.04266	0.05384	0.09650	0.04650	0.05734	0.10384	9.0%	6.5%	7.6%
SOff-Peak	0.03960	0.03013	0.06973	0.04079	0.02732	0.06811	3.0%	-9.3%	-2.3%
Customer Charge - $/month	2586.55		2,586.55	2596.75		2596.75	0.4%		0.4%
Facilities Related Demand Charge - $/kW	0.00			0.00		0.00			
Power Factor Adjustment - $/kVA	0.54		0.54	0.66		0.66	22.2%		22.2%
Voltage Discount, 220 kV and above (Demand - $/kW)									
Facilities Related	0.00			0.00		0.00			
Voltage Discount, 220 kV and above (Energy - $/kWh)	(0.01016)	(0.00065)	(0.01081)	(0.01738)	(0.00076)	(0.01814)	71.1%	16.9%	67.8%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-Rate D (Below 2kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.04230	0.08130	0.12360	0.04627	0.08384	0.13011	9.4%	3.1%	5.3%
Mid-peak	0.04230	0.07311	0.11541	0.04524	0.07645	0.12169	7.0%	4.6%	5.4%
Off-Peak	0.04230	0.04651	0.08881	0.04503	0.05116	0.09619	6.5%	10.0%	8.3%
Winter Season									
Mid-peak	0.04230	0.06110	0.10340	0.04627	0.05904	0.10531	9.4%	-3.4%	1.8%
Off-Peak	0.04230	0.05130	0.09360	0.04524	0.05941	0.10465	7.0%	15.8%	11.8%
Super-Off-Peak	0.04230	0.03288	0.07518	0.04464	0.03118	0.07582	5.5%	-5.2%	0.9%
Customer Charge - $/month	701.42	0.00	701.42	319.75	0.00	319.75	-54.4%		-54.4%
Facilities Related									
Demand Charge - $/kW	17.33	0.00	17.33	18.96	0.00	18.96	9.4%		9.4%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	14.86	22.51	37.37	14.57	16.02	30.59	-2.0%	-28.8%	-18.1%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	5.00	4.40	9.40	2.57	4.96	7.53	-48.6%	12.7%	-19.9%
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
TOU-8 (Below 2kV) - Rate E									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.21022	0.31899	0.52921	0.28460	0.25295	0.53755	35.4%	-20.7%	1.6%
Mid-peak	0.13647	0.07311	0.20958	0.16759	0.07645	0.24404	22.8%	4.6%	16.4%
Off-Peak	0.08717	0.04651	0.13368	0.09631	0.05116	0.14747	10.5%	10.0%	10.3%
Winter Season									
Mid-peak	0.06994	0.09824	0.16818	0.05653	0.09303	0.14956	-19.2%	-5.3%	-11.1%
Off-Peak	0.04622	0.05130	0.09752	0.04353	0.05941	0.10294	-5.8%	15.8%	5.6%
Super-Off-Peak	0.05949	0.03288	0.09237	0.05251	0.03118	0.08369	-11.7%	-5.2%	-9.4%
Customer Charge - $/month	701.42	0.00	701.42	319.75	0.00	319.75	-54.4%		-54.4%
Facilities Related									
Demand Charge - $/kW	11.59	0.00	11.59	11.94	0.00	11.94	3.0%		3.0%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	4.97	4.97	0.00	4.17	4.17		-16.1%	-16.1%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.00	0.93	0.93	0.00	1.89	1.89		103.2%	103.2%
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
TOU-8-Rate B (Below 2kV) - GF									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.03511	0.05746	0.09257	0.03505	0.06194	0.09699	-0.2%	7.8%	4.8%
Mid-peak	0.03511	0.05353	0.08864	0.03505	0.05764	0.09269	-0.2%	7.7%	4.6%
Off-Peak	0.03511	0.05172	0.08683	0.03505	0.05575	0.09080	-0.2%	7.8%	4.6%
Winter Season									
Mid-peak	0.03511	0.07127	0.10638	0.03505	0.07720	0.11225	-0.2%	8.3%	5.5%
Off-Peak	0.03511	0.04422	0.07933	0.03505	0.04647	0.08152	-0.2%	5.1%	2.8%
Customer Charge - $/month	701.42	0.00	701.42	319.75	0.00	319.75	-54.4%		-54.4%
Facilities Related									
Demand Charge - $/kW	27.75	0.00	27.75	28.93	0.00	28.93	4.3%		4.3%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	15.95	15.95	0.00	11.03	11.03		-30.8%	-30.8%
Mid-Peak	0.00	5.14	5.14	0.00	3.62	3.62		-29.6%	-29.6%
Winter Season									
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Off-Peak	0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8 (Below 2kV) - Rate R - GF									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.18202	0.23020	0.41222	0.19158	0.18862	0.38020	5.3%	-18.1%	-7.8%
Mid-peak	0.08445	0.09485	0.17930	0.10765	0.08848	0.19613	27.5%	-6.7%	9.4%
Off-Peak	0.04861	0.05172	0.10033	0.05900	0.05575	0.11475	21.4%	7.8%	14.4%
Winter Season									
Mid-peak	0.05420	0.07127	0.12547	0.04787	0.07720	0.12507	-11.7%	8.3%	-0.3%
Off-Peak	0.03999	0.04422	0.08421	0.03781	0.04647	0.08428	-5.5%	5.1%	0.1%
Customer Charge - $/month	701.42	0.00	701.42	319.75	0.00	319.75	-54.4%		-54.4%
Facilities Related									
Demand Charge - $/kW	17.18	0.00	17.18	17.82	0.00	17.82	3.7%		3.7%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak									
Mid-Peak									
Winter Season									
Mid-Peak									
Off-Peak									
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
TOU-8-Rate D (From 2 kV to 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.04020	0.07668	0.11688	0.04363	0.07987	0.12350	8.5%	4.2%	5.7%
Mid-peak	0.04020	0.06896	0.10916	0.04273	0.07299	0.11572	6.3%	5.8%	6.0%
Off-Peak	0.04020	0.04401	0.08421	0.04255	0.04772	0.09027	5.8%	8.4%	7.2%
Winter Season									
Mid-peak	0.04020	0.05783	0.09803	0.04363	0.05523	0.09886	8.5%	-4.5%	0.8%
Off-Peak	0.04020	0.04853	0.08873	0.04273	0.05570	0.09843	6.3%	14.8%	10.9%
Super-Off-Peak	0.04020	0.03111	0.07131	0.04217	0.02921	0.07138	4.9%	-6.1%	0.1%
Customer Charge - $/month	373.12	0.00	373.12	304.00	0.00	304.00	-18.5%		-18.5%
Facilities Related									
Demand Charge - $/kW	16.97	0.00	16.97	18.02	0.00	18.02	6.2%		6.2%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	14.05	22.19	36.24	14.22	16.53	30.75	1.2%	-25.5%	-15.1%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	4.58	4.69	9.27	2.55	5.93	8.48	-44.3%	26.4%	-8.5%
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
TOU-8 (From 2 kV to 50 kV) - Rate E									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.19428	0.30975	0.50403	0.25733	0.25545	0.51278	32.5%	-17.5%	1.7%
Mid-peak	0.11604	0.06896	0.18500	0.15092	0.07299	0.22391	30.1%	5.8%	21.0%
Off-Peak	0.07890	0.04401	0.12291	0.08578	0.04772	0.13350	8.7%	8.4%	8.6%
Winter Season									
Mid-peak	0.06412	0.09304	0.15716	0.05322	0.10752	0.16074	-17.0%	15.6%	2.3%
Off-Peak	0.04321	0.04853	0.09174	0.04119	0.05570	0.09689	-4.7%	14.8%	5.6%
Super-Off-Peak	0.05606	0.03111	0.08717	0.04925	0.02921	0.07846	-12.1%	-6.1%	-10.0%
Customer Charge - $/month	373.12	0.00	373.12	304.00	0.00	304.00	-18.5%		-18.5%
Facilities Related									
Demand Charge - $/kW	11.26	0.00	11.26	11.50	0.00	11.50	2.1%		2.1%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	4.13	4.13	0.00	3.41	3.41		-17.4%	-17.4%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.00	1.03	1.03	0.00	0.59	0.59		-42.7%	-42.7%
Off-Peak	0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-Rate B (From 2 kV to 50 kV) - GF									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.03396	0.05445	0.08841	0.03380	0.05834	0.09214	-0.5%	7.1%	4.2%
Mid-peak	0.03396	0.05050	0.08446	0.03380	0.05403	0.08783	-0.5%	7.0%	4.0%
Off-Peak	0.03396	0.04901	0.08297	0.03380	0.05250	0.08630	-0.5%	7.1%	4.0%
Winter Season									
Mid-peak	0.03396	0.07070	0.10466	0.03380	0.07969	0.11349	-0.5%	12.7%	8.4%
Off-Peak	0.03396	0.04252	0.07648	0.03380	0.04454	0.07834	-0.5%	4.8%	2.4%
Customer Charge - $/month	373.12	0.00	373.12	304.00	0.00	304.00	-18.5%		-18.5%
Facilities Related									
Demand Charge - $/kW	26.86	0.00	26.86	27.66	0.00	27.66	3.0%		3.0%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	16.46	16.46	0.00	11.64	11.64		-29.3%	-29.3%
Mid-Peak	0.00	5.14	5.14	0.00	3.74	3.74		-27.2%	-27.2%
Winter Season									
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Off-Peak	0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
TOU-8 (From 2 kV to 50 kV) - Rate R - GF									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.17370	0.22840	0.40210	0.18182	0.18998	0.37180	4.7%	-16.8%	-7.5%
Mid-peak	0.07814	0.08940	0.16754	0.09846	0.08385	0.18231	26.0%	-6.2%	8.8%
Off-Peak	0.04469	0.04901	0.09370	0.05279	0.05250	0.10529	18.1%	7.1%	12.4%
Winter Season									
Mid-peak	0.05153	0.07070	0.12223	0.04561	0.07969	0.12530	-11.5%	12.7%	2.5%
Off-Peak	0.03780	0.04252	0.08032	0.03598	0.04454	0.08052	-4.8%	4.8%	0.2%
Customer Charge - $/month	373.12	0.00	373.12	304.00	0.00	304.00	-18.5%		-18.5%
Facilities Related									
Demand Charge - $/kW	16.83	0.00	16.83	17.27	0.00	17.27	2.6%		2.6%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak									
Mid-Peak									
Winter Season									
Mid-Peak									
Off-Peak									
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
TOU-8-Rate D (Above 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.0303	0.07172	0.10202	0.02971	0.07349	0.10320	-1.9%	2.5%	1.2%
Mid-peak	0.0303	0.06462	0.09492	0.02971	0.06735	0.09706	-1.9%	4.2%	2.3%
Off-Peak	0.0303	0.04251	0.07281	0.02971	0.04449	0.07420	-1.9%	4.7%	1.9%
Winter Season									
Mid-peak	0.0303	0.05590	0.08620	0.02971	0.05149	0.08120	-1.9%	-7.9%	-5.8%
Off-Peak	0.0303	0.04711	0.07741	0.02971	0.05211	0.08182	-1.9%	10.6%	5.7%
Super-Off-Peak	0.0303	0.03013	0.06043	0.02971	0.02732	0.05703	-1.9%	-9.3%	-5.6%
Customer Charge - $/month	2,586.55	0.00	2,586.55	2,596.75	0.00	2,596.75	0.4%		0.4%
Facilities Related									
Demand Charge - $/kW	7.40	0.00	7.40	8.99	0.00	8.99	21.5%		21.5%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	6.65	21.87	28.52	4.90	16.33	21.23	-26.3%	-25.3%	-25.6%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.77	5.45	6.22	0.56	5.09	5.65	-27.3%	-6.6%	-9.2%
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
Voltage Discount, 220 kV and above									
Facilities Related Demand - $/kW	(2.82)	0.00	(2.82)	(4.39)	0.00	(4.39)	55.7%		55.7%
Time-Related Demand - $/kW									
Summer On-Peak	(2.75)	(0.11)	(2.86)	(4.90)	(0.17)	(5.07)	78.2%	54.5%	77.3%
Winter Mid-Peak	(2.75)	(0.11)	(2.86)	(0.56)	(0.05)	(0.61)	-79.6%	-54.5%	-78.7%
Energy - $/kWh	0.00000	(0.00046)	(0.00046)	0.00000	(0.00046)	(0.00046)		0.0%	0.0%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8 (Above 50 kV) - Rate E									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.10728	0.31197	0.41925	0.09026	0.25313	0.34339	-15.9%	-18.9%	-18.1%
Mid-peak	0.06006	0.06462	0.12468	0.06487	0.06735	0.13222	8.0%	4.2%	6.0%
Off-Peak	0.03817	0.04251	0.08068	0.03848	0.04449	0.08297	0.8%	4.7%	2.8%
Winter Season									
Mid-peak	0.03670	0.09757	0.13427	0.03470	0.08929	0.12399	-5.4%	-8.5%	-7.7%
Off-Peak	0.03042	0.04711	0.07753	0.03033	0.05211	0.08244	-0.3%	10.6%	6.3%
Super-Off-Peak	0.03134	0.03013	0.06147	0.03081	0.02732	0.05813	-1.7%	-9.3%	-5.4%
Customer Charge - $/month	2586.55	0.00	2,586.55	2596.75	0.00	2596.75	0.4%		0.4%
Facilities Related									
Demand Charge - $/kW	5.85	0.00	5.85	7.12	0.00	7.12	21.7%		21.7%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	1.55	1.55	0.00	1.36	1.36		-12.3%	-12.3%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.00	0.33	0.33	0.00	0.67	0.67		103.0%	103.0%
Off-Peak	0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
Voltage Discount, 220 kV and above									
Facilities Related Demand - $	(1.27)	0.00	(1.27)	(2.54)	0.00	(2.54)	100.0%		100.0%
Time-Related Demand - $/kW									
Summer On-Peak	0.00	(0.01)	(0.01)	0.00	(0.01)	(0.01)		0.0%	0.0%
Winter Mid-Peak	0.00	(0.01)	(0.01)	0.00	(0.01)	(0.01)		0.0%	0.0%
Energy - $/kWh	(0.00777)	(0.00064)	(0.00841)	(0.00724)	(0.00060)	(0.00784)	-6.8%	-6.3%	-6.8%
TOU-8-Rate B (Above 50 kV) - GF									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.0303	0.05205	0.08235	0.02975	0.05417	0.08392	-1.8%	4.1%	1.9%
Mid-peak	0.0303	0.04810	0.07840	0.02975	0.05001	0.07976	-1.8%	4.0%	1.7%
Off-Peak	0.0303	0.04684	0.07714	0.02975	0.04875	0.07850	-1.8%	4.1%	1.8%
Winter Season									
Mid-peak	0.0303	0.07060	0.10090	0.02975	0.07057	0.10032	-1.8%	0.0%	-0.6%
Off-Peak	0.0303	0.04153	0.07183	0.02975	0.04204	0.07179	-1.8%	1.2%	-0.1%
Customer Charge - $/month	2586.55	0.00	2,586.55	2596.75	0.00	2,596.75	0.4%		0.4%
Facilities Related									
Demand Charge - $/kW	10.01	0.00	10.01	10.86	0.00	10.86	8.5%		8.5%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	16.22	16.22	0.00	11.89	11.89		-26.7%	-26.7%
Mid-Peak	0.00	5.22	5.22	0.00	3.85	3.85		-26.2%	-26.2%
Winter Season									
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Off-Peak	0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
Voltage Discount, 220 kV and above									
Facilities Related Demand - $/kW	(5.43)	0.00	(5.43)	(6.28)	0.00	(6.28)	15.7%		15.7%
Time-Related Demand - $/kW									
Summer	0.00	(0.16)	(0.16)	0.00	(0.25)	(0.25)		56.3%	56.3%
Energy - $/kWh	0.00000	(0.00046)	(0.00046)	0.00000	(0.00046)	(0.00046)		0.0%	0.0%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8 (Above 50 kV) - Rate R - GF									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.08482	0.21306	0.29788	0.07897	0.17443	0.25340	-6.9%	-18.1%	-14.9%
Mid-peak	0.04723	0.08317	0.13040	0.05107	0.07644	0.12751	8.1%	-8.1%	-2.2%
Off-Peak	0.03401	0.04684	0.08085	0.03544	0.04875	0.08419	4.2%	4.1%	4.1%
Winter Season									
Mid-peak	0.03679	0.07060	0.10739	0.03344	0.07057	0.10401	-9.1%	0.0%	-3.1%
Off-Peak	0.03154	0.04153	0.07307	0.03037	0.04204	0.07241	-3.7%	1.2%	-0.9%
Customer Charge - $/month	2586.55	0.00	2,586.55	2596.75	0.00	2596.75	0.4%		0.4%
Facilities Related									
Demand Charge - $/kW	5.85	0.00	5.85	7.12	0.00	7.12	21.7%		21.7%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak									
Mid-Peak									
Winter Season									
Mid-Peak									
Off-Peak									
Power Factor Adjustment - $/kVA	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
Voltage Discount, 220 kV and above									
Facilities Related Demand - $	(1.27)	0.00	(1.27)	(2.54)	0.00	(2.54)	100.0%		100.0%
Time-Related Demand - $/kW									
Summer	0.00	0.00		0.00	0.00	0.00			
Energy - $/kWh	(0.00787)	(0.00065)	(0.00852)	(0.00724)	(0.00076)	(0.00800)	-8.0%	16.9%	-6.1%
TOU-8-Backup-D (Below 2kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.03511	0.08130	0.11641	0.03505	0.08384	0.11889	-0.2%	3.1%	2.1%
Mid-peak	0.03511	0.07311	0.10822	0.03505	0.07645	0.11150	-0.2%	4.6%	3.0%
Off-Peak	0.03511	0.04651	0.08162	0.03505	0.05116	0.08621	-0.2%	10.0%	5.6%
Winter Season									
Mid-peak	0.03511	0.06110	0.09621	0.03505	0.05904	0.09409	-0.2%	-3.4%	-2.2%
Off-Peak	0.03511	0.05130	0.08641	0.03505	0.05941	0.09446	-0.2%	15.8%	9.3%
Super-Off-Peak	0.03511	0.03288	0.06799	0.03505	0.03118	0.06623	-0.2%	-5.2%	-2.6%
Customer Charge - $/month	213.41	0.00	213.41	271.00	0.00	271.00	27.0%		27.0%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	22.51	22.51	0.00	16.02	16.02		-28.8%	-28.8%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.00	4.40	4.40	0.00	4.96	4.96		12.7%	12.7%
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
TOU-8-Backup-D (From 2 kV to 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.03396	0.07668	0.11064	0.03380	0.07987	0.11367	-0.5%	4.2%	2.7%
Mid-peak	0.03396	0.06896	0.10292	0.03380	0.07299	0.10679	-0.5%	5.8%	3.8%
Off-Peak	0.03396	0.04401	0.07797	0.03380	0.04772	0.08152	-0.5%	8.4%	4.6%
Winter Season									
Mid-peak	0.03396	0.05783	0.09179	0.03380	0.05523	0.08903	-0.5%	-4.5%	-3.0%
Off-Peak	0.03396	0.04853	0.08249	0.03380	0.05570	0.08950	-0.5%	14.8%	8.5%
Super-Off-Peak	0.03396	0.03111	0.06507	0.03380	0.02921	0.06301	-0.5%	-6.1%	-3.2%
Customer Charge - $/month	373.12	0.00	373.12	260.25	0.00	260.25	-30.3%		-30.3%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	22.19	22.19	0.00	16.53	16.53		-25.5%	-25.5%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.00	4.69	4.69	0.00	5.93	5.93		26.4%	26.4%
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-Backup-D (Above 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.03030	0.07172	0.10202	0.02975	0.07349	0.10324	-1.8%	2.5%	1.2%
Mid-peak	0.03030	0.06462	0.09492	0.02975	0.06735	0.09710	-1.8%	4.2%	2.3%
Off-Peak	0.03030	0.04251	0.07281	0.02975	0.04449	0.07424	-1.8%	4.7%	2.0%
Winter Season									
Mid-peak	0.03030	0.05590	0.08620	0.02975	0.05149	0.08124	-1.8%	-7.9%	-5.8%
Off-Peak	0.03030	0.04711	0.07741	0.02975	0.05211	0.08186	-1.8%	10.6%	5.7%
Super-Off-Peak	0.03030	0.03013	0.06043	0.02975	0.02732	0.05707	-1.8%	-9.3%	-5.6%
Customer Charge - $/month	2,586.55	0.00	2,586.55	2,543.25	0.00	2,543.25	-1.7%		-1.7%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	0.00	21.87	21.87	0.00	16.33	16.33		-25.3%	-25.3%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.00	5.45	5.45	0.00	5.09	5.09		-6.6%	-6.6%
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
Voltage Discount, 220 kV and above									
Facilities Related Demand - $/kW	0.00	0.00	0.00	0.00	0.00	0.00			
Time-Related Demand - $/kW									
Summer On-Peak	0.00	(0.11)	(0.11)	0.00	(0.17)	(0.17)		54.5%	54.5%
Winter Mid-Peak	0.00	(0.11)	(0.11)	0.00	(0.05)	(0.05)		-54.5%	-54.5%
Energy - $/kWh	0.00000	(0.00046)	(0.00046)	0.00000	(0.00046)	(0.00046)		0.0%	0.0%
TOU-8-CPP (Below 2kV)									
Critical Peak Pricing									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.04230	0.08130	0.12360	0.04636	0.08384	0.13020	9.6%	3.1%	5.3%
Mid-peak	0.04230	0.07311	0.11541	0.04533	0.07645	0.12178	7.2%	4.6%	5.5%
Off-Peak	0.04230	0.04651	0.08881	0.04512	0.05116	0.09628	6.7%	10.0%	8.4%
Winter Season									
Mid-peak	0.04230	0.06110	0.10340	0.04636	0.05904	0.10540	9.6%	-3.4%	1.9%
Off-Peak	0.04230	0.05130	0.09360	0.04533	0.05941	0.10474	7.2%	15.8%	11.9%
Super-Off-Peak	0.04230	0.03288	0.07518	0.04473	0.03118	0.07591	5.7%	-5.2%	1.0%
Customer Charge - $/month	701.42	0.00	701.42	319.75	0.00	319.75	-54.4%		-54.4%
Facilities Related									
Demand Charge - $/kW	17.33	0.00	17.33	18.93	0.00	18.93	9.2%		9.2%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	14.86	22.51	37.37	14.57	16.02	30.59	-2.0%	-28.8%	-18.1%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Off-Peak			0.00						
Winter Season									
Mid-Peak	5.00	4.40	9.40	2.57	4.96	7.53	-48.6%	12.7%	-19.9%
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
CPP Event Energy Charge - $/kWh	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer CPP Non-Event Credit									
On-Peak Demand Credit - $/kW	0.00	(8.22)	(8.22)	0.00	(8.22)	(8.22)		0.0%	0.0%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-CPP (From 2 kV to 50 kV)									
Critical Peak Pricing									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.04020	0.07668	0.11688	0.04371	0.07987	0.12358	8.7%	4.2%	5.7%
Mid-peak	0.04020	0.06896	0.10916	0.04281	0.07299	0.11580	6.5%	5.8%	6.1%
Off-Peak	0.04020	0.04401	0.08421	0.04263	0.04772	0.09035	6.0%	8.4%	7.3%
Winter Season									
Mid-peak	0.04020	0.05783	0.09803	0.04371	0.05523	0.09894	8.7%	-4.5%	0.9%
Off-Peak	0.04020	0.04853	0.08873	0.04281	0.05570	0.09851	6.5%	14.8%	11.0%
Super-Off-Peak	0.04020	0.03111	0.07131	0.04225	0.02921	0.07146	5.1%	-6.1%	0.2%
Customer Charge - $/month	373.12	0.00	373.12	304.00	0.00	304.00	-18.5%		-18.5%
Facilities Related									
Demand Charge - $/kW	16.97	0.00	16.97	17.98	0.00	17.98	6.0%		6.0%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	14.05	22.19	36.24	14.22	16.53	30.75	1.2%	-25.5%	-15.1%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Off-Peak			0.00						
Winter Season									
Mid-Peak	4.58	4.69	9.27	2.55	5.93	8.48	-44.3%	26.4%	-8.5%
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
CPP Event Energy Charge - $/kWh	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer CPP Non-Event Credit									
On-Peak Demand Credit - $/kW	0.00	(8.52)	(8.52)	0.00	(8.52)	(8.52)		0.0%	0.0%
TOU-8-CPP (Above 50 kV)									
Critical Peak Pricing									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.03030	0.07172	0.10202	0.02975	0.07349	0.10324	-1.8%	2.5%	1.2%
Mid-peak	0.03030	0.06462	0.09492	0.02975	0.06735	0.09710	-1.8%	4.2%	2.3%
Off-Peak	0.03030	0.04251	0.07281	0.02975	0.04449	0.07424	-1.8%	4.7%	2.0%
Winter Season									
Mid-peak	0.03030	0.05590	0.08620	0.02975	0.05149	0.08124	-1.8%	-7.9%	-5.8%
Off-Peak	0.03030	0.04711	0.07741	0.02975	0.05211	0.08186	-1.8%	10.6%	5.7%
Super-Off-Peak	0.03030	0.03013	0.06043	0.02975	0.02732	0.05707	-1.8%	-9.3%	-5.6%
Customer Charge - $/month	2,586.55	0.00	2,586.55	2,596.75	0.00	2,596.75	0.4%		0.4%
Facilities Related									
Demand Charge - $/kW	7.40	0.00	7.40	8.97	0.00	8.97	21.2%		21.2%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	6.65	21.87	28.52	4.90	16.33	21.23	-26.3%	-25.3%	-25.6%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Off-Peak			0.00						
Winter Season									
Mid-Peak	0.77	5.45	6.22	0.56	5.09	5.65	-27.3%	-6.6%	-9.2%
Off-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
CPP Event Energy Charge - $/kWh	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer CPP Non-Event Credit									
On-Peak Demand Credit - $/kW	0.00	(8.44)	(8.44)	0.00	(8.44)	(8.44)		0.0%	0.0%
Voltage Discount, 220 kV and above									
Facilities Related Demand - $/kW	(2.82)	0.00	(2.82)	(4.39)	0.00	(4.39)	55.7%		55.7%
Time-Related Demand - $/kW									
Summer On-Peak	(2.75)	(0.11)	(2.86)	(4.90)	(0.17)	(5.07)	78.2%	54.5%	77.3%
Winter Mid-Peak	(2.75)	(0.11)	(2.86)	(0.56)	(0.05)	(0.61)	-79.6%	-54.5%	-78.7%
Energy - $/kWh	0.00000	(0.00046)	(0.00046)	0.00000	(0.00046)	(0.00046)		0.0%	0.0%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-RTP (Below 2kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.04230	Variable*	Variable*	0.04636	Variable*	Variable*	9.6%		
Mid-peak	0.04230	Variable*		0.04533	Variable*	Variable*	7.2%		
Off-Peak	0.04230	Variable*		0.04512	Variable*	Variable*	6.7%		
Winter Season									
Mid-peak	0.04230	Variable*		0.04636	Variable*	Variable*	9.6%		
Off-Peak	0.04230	Variable*		0.04533	Variable*	Variable*	7.2%		
Super-Off-Peak	0.04230	Variable*		0.04473	Variable*	Variable*	5.7%		
Customer Charge - $/month	701.42	0.00	701.42	319.75	0.00	319.75	-54.4%		-54.4%
Facilities Related									
Demand Charge - $/kW	17.33	0.00	17.33	18.93	0.00	18.93	9.2%		9.2%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	14.86	0.00	14.86	14.57	0.00	14.57	-2.0%		-2.0%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Winter Season									
Mid-Peak	5.00	0.00	5.00	2.57	0.00	2.57	-48.6%		-48.6%
Off-Peak	0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
TOU-8-RTP (From 2 kV to 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.04020	Variable*	Variable*	0.04371	Variable*	Variable*	8.7%		
Mid-peak	0.04020	Variable*		0.04281	Variable*	Variable*	6.5%		
Off-Peak	0.04020	Variable*		0.04263	Variable*	Variable*	6.0%		
Winter Season									
Mid-peak	0.04020	Variable*		0.04371	Variable*	Variable*	8.7%		
Off-Peak	0.04020	Variable*		0.04281	Variable*	Variable*	6.5%		
Super-Off-Peak	0.04020	Variable*		0.04225	Variable*	Variable*	5.1%		
Customer Charge - $/month	373.12	0.00	373.12	304.00	0.00	304.00	-18.5%		-18.5%
Facilities Related									
Demand Charge - $/kW	16.97	0.00	16.97	17.98	0.00	17.98	6.0%		6.0%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	14.05	0.00	14.05	14.22	0.00	14.22	1.2%		1.2%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Winter Season									
Mid-Peak	4.58	0.00	4.58	2.55	0.00	2.55	-44.3%		-44.3%
Off-Peak	0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
TOU-8-RTP (Above 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.03030	Variable*	Variable*	0.02975	Variable*	Variable*	-1.8%		
Mid-peak	0.03030	Variable*		0.02975	Variable*	Variable*	-1.8%		
Off-Peak	0.03030	Variable*		0.02975	Variable*	Variable*	-1.8%		
Winter Season									
Mid-peak	0.03030	Variable*		0.02975	Variable*	Variable*	-1.8%		
Off-Peak	0.03030	Variable*		0.02975	Variable*	Variable*	-1.8%		
Super-Off-Peak	0.03030	Variable*		0.02975	Variable*	Variable*	-1.8%		
Customer Charge - $/month	2,586.55	0.00	2,586.55	2,596.75	0.00	2,596.75	0.4%		0.4%
Facilities Related									
Demand Charge - $/kW	7.40	0.00	7.40	8.97	0.00	8.97	21.2%		21.2%
Time Related Demand Charge - $/kW									
Summer Season									
On-Peak	6.65	0.00	6.65	4.90	0.00	4.90	-26.3%		-26.3%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.77	0.00	0.77	0.56	0.00	0.56	-27.3%		-27.3%
Off-Peak	0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
Voltage Discount, 220 kV and above									
Facilities Related Demand - $/kW	(2.82)	0.00	(2.82)	(4.39)	0.00	(4.39)	55.7%		55.7%
Time-Related Demand - $/kW									
Summer On-Peak	(2.75)	0.00	(2.75)	(4.90)	0.00	(4.90)	78.2%		78.2%
Winter Mid-Peak	(2.75)	0.00	(2.75)	(0.56)	0.00	(0.56)	-79.6%		-79.6%
Energy - $/kWh	0.00000	(0.00064)	(0.00064)	0.00000	(0.00060)	(0.00060)		-6.3%	-6.3%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-BIP Rate - $/kW (Applicable: Average kW demand)									
Rate A									
BIP Rate Credit ($/KW)									
Below 2 kV - Summer Average On Peak	(26.11)		(26.11)	(26.11)		(26.11)	0.0%		0.0%
Summer Average Mid - Peak	(2.04)		(2.04)	(2.04)		(2.04)	0.0%		0.0%
Winter Average Mid - Peak	(10.97)		(10.97)	(10.97)		(10.97)	0.0%		0.0%
Excess Energy Charge - $/kWh	14.98186		14.98186	14.98186		14.98186	0.0%		0.0%
From 2 kV to 50 kV - Summer Average On Peak	(26.11)		(26.11)	(26.11)		(26.11)	0.0%		0.0%
Summer Average Mid - Peak	(1.70)		(1.70)	(1.70)		(1.70)	0.0%		0.0%
Winter Average Mid - Peak	(10.26)		(10.26)	(10.26)		(10.26)	0.0%		0.0%
Excess Energy Charge - $/kWh	14.69333		14.69333	14.69333		14.69333	0.0%		0.0%
above 50 kV - Summer Average On Peak	(17.84)		(17.84)	(17.84)		(17.84)	0.0%		0.0%
Summer Average Mid - Peak	(0.86)		(0.86)	(0.86)		(0.86)	0.0%		0.0%
Winter Average Mid - Peak	(6.46)		(6.46)	(6.46)		(6.46)	0.0%		0.0%
Excess Energy Charge - $/kWh	14.18881		14.18881	14.18881		14.18881	0.0%		0.0%
Rate B									
BIP Rate Credit ($/KW)									
Below 2 kV - Summer Average On Peak	(23.54)		(23.54)	(23.54)		(23.54)	0.0%		0.0%
Summer Average Mid - Peak	(1.84)		(1.84)	(1.84)		(1.84)	0.0%		0.0%
Winter Average Mid - Peak	(9.89)		(9.89)	(9.89)		(9.89)	0.0%		0.0%
Excess Energy Charge - $/kWh	13.51232		13.51232	13.51232		13.51232	0.0%		0.0%
From 2 kV to 50 kV - Summer Average On Peak	(23.14)		(23.14)	(23.14)		(23.14)	0.0%		0.0%
Summer Average Mid - Peak	(1.50)		(1.50)	(1.50)		(1.50)	0.0%		0.0%
Winter Average Mid - Peak	(9.07)		(9.07)	(9.07)		(9.07)	0.0%		0.0%
Excess Energy Charge - $/kWh	13.22378		13.22378	13.22378		13.22378	0.0%		0.0%
above 50 kV - Summer Average On Peak	(15.37)		(15.37)	(15.37)		(15.37)	0.0%		0.0%
Summer Average Mid - Peak	(0.73)		(0.73)	(0.73)		(0.73)	0.0%		0.0%
Winter Average Mid - Peak	(5.54)		(5.54)	(5.54)		(5.54)	0.0%		0.0%
Excess Energy Charge - $/kWh	12.71927		12.71927	12.71927		12.71927	0.0%		0.0%
TOU-8-S Rate D (Below 2kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.04076	0.08130	0.12206	0.04540	0.08384	0.12924	11.4%	3.1%	5.9%
Mid-peak	0.04076	0.07311	0.11387	0.04437	0.07645	0.12082	8.9%	4.6%	6.1%
Off-Peak	0.04076	0.04651	0.08727	0.04416	0.05116	0.09532	8.3%	10.0%	9.2%
Winter Season									
Mid-peak	0.04076	0.06110	0.10186	0.04540	0.05904	0.10444	11.4%	-3.4%	2.5%
Off-Peak	0.04076	0.05130	0.09206	0.04437	0.05941	0.10378	8.9%	15.8%	12.7%
Super-Off-Peak	0.04076	0.03288	0.07364	0.04377	0.03118	0.07495	7.4%	-5.2%	1.8%
Customer Charge - $/month	701.42	0.00	701.42	319.75	0.00	319.75	-54.4%		-54.4%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	17.33	0.00	17.33	18.96	0.00	18.96	9.4%		9.4%
Standby (CRC) - $/kW	16.51	0.00	16.51	16.48	0.00	16.48	-0.2%		-0.2%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	11.44	19.87	31.31	11.95	16.68	28.63	4.5%	-16.1%	-8.6%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	3.31	3.71	7.02	2.12	7.54	9.66	-36.0%	103.2%	37.6%
Supplemental demand - Summer Season									
On-Peak	14.86	22.51	37.37	14.57	16.02	30.59	-2.0%	-28.8%	-18.1%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	5.00	4.40	9.40	2.57	4.96	7.53	-48.6%	12.7%	-19.9%
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-S-Rate LG (Below 2kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.07432	0.38630	0.46062	0.08171	0.31246	0.39417	9.9%	-19.1%	-14.4%
Mid-peak	0.07432	0.07311	0.14743	0.08068	0.07645	0.15713	8.6%	4.6%	6.6%
Off-Peak	0.07432	0.04651	0.12083	0.07710	0.05116	0.12826	3.7%	10.0%	6.1%
Winter Season									
Mid-peak	0.07432	0.10816	0.18248	0.08171	0.11386	0.19557	9.9%	5.3%	7.2%
Off-Peak	0.07432	0.05130	0.12562	0.07731	0.05941	0.13672	4.0%	15.8%	8.8%
Super-Off-Peak	0.07432	0.03288	0.10720	0.07512	0.03118	0.10630	1.1%	-5.2%	-0.8%
Customer Charge - $/month	701.42	0.00	701.42	319.75	0.00	319.75	-54.4%		-54.4%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	11.59	0.00	11.59	11.94	0.00	11.94	3.0%		3.0%
Standby (CRC) - $/kW	16.51	0.00	16.51	16.48	0.00	16.48	-0.2%		-0.2%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	11.44	19.87	31.31	11.95	16.68	28.63	4.5%	-16.1%	-8.6%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.00	3.71	3.71	2.12	7.54	9.66		103.2%	160.4%
Supplemental demand - Summer Season									
On-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
TOU-8-S-B (Below 2kV) - GF									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.03357	0.05746	0.09103	0.03418	0.06194	0.09612	1.8%	7.8%	5.6%
Mid-peak	0.03357	0.05353	0.08710	0.03418	0.05764	0.09182	1.8%	7.7%	5.4%
Off-Peak	0.03357	0.05172	0.08529	0.03418	0.05575	0.08993	1.8%	7.8%	5.4%
Winter Season									
Mid-peak	0.03357	0.07152	0.10509	0.03418	0.07777	0.11195	1.8%	8.7%	6.5%
Off-Peak	0.03357	0.04422	0.07779	0.03418	0.04647	0.08065	1.8%	5.1%	3.7%
Customer Charge - $/month	701.42	0.00	701.42	319.75	0.00	319.75	-54.4%		-54.4%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	27.75	0.00	27.75	28.93	0.00	28.93	4.3%		4.3%
Standby (CRC) - $/kW	21.06	0.00	21.06	20.62	0.00	20.62	-2.1%		-2.1%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	0.00	19.93	19.93	0.00	15.12	15.12		-24.1%	-24.1%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Supplemental demand - Summer Season									
On-Peak	0.00	15.95	15.95	0.00	11.03	11.03		-30.8%	-30.8%
Mid-Peak	0.00	5.14	5.14	0.00	3.62	3.62		-29.6%	-29.6%
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
TOU-8-S-Rate A (Below 2kV) - GF									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.18048	0.23020	0.41068	0.19071	0.18862	0.37933	5.7%	-18.1%	-7.6%
Mid-peak	0.08291	0.09485	0.17776	0.10678	0.08848	0.19526	28.8%	-6.7%	9.8%
Off-Peak	0.04707	0.05172	0.09879	0.05813	0.05575	0.11388	23.5%	7.8%	15.3%
Winter Season									
Mid-peak	0.05266	0.07152	0.12418	0.04700	0.07777	0.12477	-10.7%	8.7%	0.5%
Off-Peak	0.03845	0.04422	0.08267	0.03694	0.04647	0.08341	-3.9%	5.1%	0.9%
Customer Charge - $/month	701.42	0.00	701.42	319.75	0.00	319.75	-54.4%		-54.4%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	17.18	0.00	17.18	17.82	0.00	17.82	3.7%		3.7%
Standby (CRC) - $/kW	21.06	0.00	21.06	20.62	0.00	20.62	-2.1%		-2.1%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	0.00	19.93	19.93	0.00	15.12	15.12		-24.1%	-24.1%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Supplemental demand - Summer Season									
On-Peak	0.00	0.00		0.00	0.00	0.00			
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-S Rate D (From 2 kV to 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.04160	0.07668	0.11828	0.04562	0.07987	0.12549	9.7%	4.2%	6.1%
Mid-peak	0.04160	0.06896	0.11056	0.04472	0.07299	0.11771	7.5%	5.8%	6.5%
Off-Peak	0.04160	0.04401	0.08561	0.04454	0.04772	0.09226	7.1%	8.4%	7.8%
Winter Season									
Mid-peak	0.04160	0.05783	0.09943	0.04562	0.05523	0.10085	9.7%	-4.5%	1.4%
Off-Peak	0.04160	0.04853	0.09013	0.04472	0.05570	0.10042	7.5%	14.8%	11.4%
Super-Off-Peak	0.04160	0.03111	0.07271	0.04416	0.02921	0.07337	6.2%	-6.1%	0.9%
Customer Charge - $/month	373.12	0.00	373.12	304.00	0.00	304.00	-18.5%		-18.5%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	16.97	0.00	16.97	18.02	0.00	18.02	6.2%		6.2%
Standby (CRC) - $/kW	10.86	0.00	10.86	10.04	0.00	10.04	-7.6%		-7.6%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	8.71	16.52	25.23	10.44	13.64	24.08	19.9%	-17.4%	-4.6%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	2.59	4.13	6.72	1.62	2.35	3.97	-37.5%	-43.1%	-40.9%
Supplemental demand - Summer Season									
On-Peak	14.05	22.19	36.24	14.22	16.53	30.75	1.2%	-25.5%	-15.1%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	4.58	4.69	9.27	2.55	5.93	8.48	-44.3%	26.4%	-8.5%
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
TOU-8-S-Rate LG (From 2 kV to 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.07047	0.36305	0.43352	0.07665	0.30108	0.37773	8.8%	-17.1%	-12.9%
Mid-peak	0.07047	0.06896	0.13943	0.07575	0.07299	0.14874	7.5%	5.8%	6.7%
Off-Peak	0.07047	0.04401	0.11448	0.07274	0.04772	0.12046	3.2%	8.4%	5.2%
Winter Season									
Mid-peak	0.07047	0.10298	0.17345	0.07665	0.11327	0.18992	8.8%	10.0%	9.5%
Off-Peak	0.07047	0.04853	0.11900	0.07292	0.05570	0.12862	3.5%	14.8%	8.1%
Super-Off-Peak	0.07047	0.03111	0.10158	0.07087	0.02921	0.10008	0.6%	-6.1%	-1.5%
Customer Charge - $/month	373.12	0.00	373.12	304.00	0.00	304.00	-18.5%		-18.5%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	11.26	0.00	11.26	11.50	0.00	11.50	2.1%		2.1%
Standby (CRC) - $/kW	10.86	0.00	10.86	10.04	0.00	10.04	-7.6%		-7.6%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	8.71	16.52	25.23	10.44	13.64	24.08	19.9%	-17.4%	-4.6%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.00	4.13	4.13	1.62	2.35	3.97		-43.1%	-3.9%
Supplemental demand - Summer Season									
On-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-S-B (From 2 kV to 50 kV) - GF									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.03536	0.05445	0.08981	0.03580	0.05834	0.09414	1.24%	7.1%	4.8%
Mid-peak	0.03536	0.05050	0.08586	0.03580	0.05403	0.08983	1.24%	7.0%	4.6%
Off-Peak	0.03536	0.04901	0.08437	0.03580	0.05250	0.08830	1.24%	7.1%	4.7%
Winter Season									
Mid-peak	0.03536	0.07213	0.10749	0.03580	0.08045	0.11625	1.24%	11.5%	8.1%
Off-Peak	0.03536	0.04252	0.07788	0.03580	0.04454	0.08034	1.24%	4.8%	3.2%
Customer Charge - $/month	373.12	0.00	373.12	304.00	0.00	304.00	-18.5%		-18.5%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	26.86	0.00	26.86	27.66	0.00	27.66	3.0%		3.0%
Standby (CRC) - $/kW	13.46	0.00	13.46	12.54	0.00	12.54	-6.8%		-6.8%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	0.00	15.71	15.71	0.00	12.79	12.79		-18.6%	-18.6%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Supplemental demand - Summer Season									
On-Peak	0.00	16.46	16.46	0.00	11.64	11.64		-29.3%	-29.3%
Mid-Peak	0.00	5.14	5.14	0.00	3.74	3.74		-27.2%	-27.2%
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
TOU-8-S-Rate A (From 2 kV to 50 kV) - GF									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.17510	0.22840	0.40350	0.18382	0.18998	0.37380	5.0%	-16.8%	-7.4%
Mid-peak	0.07954	0.08940	0.16894	0.10046	0.08385	0.18431	26.3%	-6.2%	9.1%
Off-Peak	0.04609	0.04901	0.09510	0.05479	0.05250	0.10729	18.9%	7.1%	12.8%
Winter Season									
Mid-peak	0.05293	0.07213	0.12506	0.04761	0.08045	0.12806	-10.1%	11.5%	2.4%
Off-Peak	0.03920	0.04252	0.08172	0.03798	0.04454	0.08252	-3.1%	4.8%	1.0%
Customer Charge - $/month	373.12	0.00	373.12	304.00	0.00	304.00	-18.5%		-18.5%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	16.83	0.00	16.83	17.27	0.00	17.27	2.6%		2.6%
Standby (CRC) - $/kW	13.46	0.00	13.46	12.54	0.00	12.54	-6.8%		-6.8%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	0.00	15.71	15.71	0.00	12.79	12.79		-18.6%	-18.6%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Supplemental demand - Summer Season									
On-Peak	0.00	0.00		0.00	0.00	0.00			
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-S Rate D (Above 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.03003	0.07172	0.10175	0.03007	0.07349	0.10356	0.1%	2.5%	1.8%
Mid-peak	0.03003	0.06462	0.09465	0.03007	0.06735	0.09742	0.1%	4.2%	2.9%
Off-Peak	0.03003	0.04251	0.07254	0.03007	0.04449	0.07456	0.1%	4.7%	2.8%
Winter Season									
Mid-peak	0.03003	0.05590	0.08593	0.03007	0.05149	0.08156	0.1%	-7.9%	-5.1%
Off-Peak	0.03003	0.04711	0.07714	0.03007	0.05211	0.08218	0.1%	10.6%	6.5%
Super-Off-Peak	0.03003	0.03013	0.06016	0.03007	0.02732	0.05739	0.1%	-9.3%	-4.6%
Customer Charge - $/month	2,586.55	0.00	2,586.55	2,596.75	0.00	2,596.75	0.4%		0.4%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	7.40	0.00	7.40	8.99	0.00	8.99	21.5%		21.5%
Standby (CRC) - $/kW	0.92	0.00	0.92	0.99	0.00	0.99	7.6%		7.6%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	1.59	6.19	7.78	1.48	5.42	6.90	-6.9%	-12.4%	-11.3%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.14	1.30	1.44	0.19	2.68	2.87	35.7%	106.2%	99.3%
Supplemental demand - Summer Season									
On-Peak	6.65	21.87	28.52	4.90	16.33	21.23	-26.3%	-25.3%	-25.6%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.77	5.45	6.22	0.56	5.09	5.65	-27.3%	-6.6%	-9.2%
Power Factor Adjustment - $/kVA	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
Voltage Discount, 220 kV and above									
Facilities Related Demand (Excess FRD) - $k/W	(2.93)	0.00	(2.93)	(4.39)	0.00	(4.39)	49.8%		49.8%
Time-Related Demand - $/kW									
Backup Summer On-Peak	(0.55)	(0.02)	(0.57)	(1.48)	(0.06)	(1.54)	169.1%	200.0%	170.2%
Backup Winter Mid-Peak	(0.55)	(0.02)	(0.57)	(0.19)	(0.03)	(0.22)	-65.5%	50.0%	-61.4%
Supplemental Summer On-Peak	(2.89)	(0.11)	(3.00)	(4.90)	(0.17)	(5.07)	69.6%	54.5%	69.0%
Supplemental Winter Mid-Peak	(2.89)	(0.11)	(3.00)	(0.56)	(0.05)	(0.61)	-80.6%	-54.5%	-79.7%
Energy - $/kWh	0.00000	(0.00045)	(0.00045)	0.00000	(0.00046)	(0.00046)		2.2%	2.2%
Standby (CRC) - $/kW	(0.33)	0.00	(0.33)	(0.40)	0.00	(0.40)	21.2%		21.2%
TOU-8-S-Rate LG (Above 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.05628	0.33026	0.38654	0.05154	0.26938	0.32092	-8.4%	-18.4%	-17.0%
Mid-peak	0.05628	0.06462	0.12090	0.05154	0.06735	0.11889	-8.4%	4.2%	-1.7%
Off-Peak	0.03384	0.04251	0.07635	0.03456	0.04449	0.07905	2.1%	4.7%	3.5%
Winter Season									
Mid-peak	0.05628	0.10021	0.15649	0.05154	0.09502	0.14656	-8.4%	-5.2%	-6.3%
Off-Peak	0.03384	0.04711	0.08095	0.03456	0.05211	0.08667	2.1%	10.6%	7.1%
Super-Off-Peak	0.03107	0.03013	0.06120	0.03117	0.02732	0.05849			
Customer Charge - $/month	2,586.55	0.00	2,586.55	2,596.75	0.00	2,596.75	0.4%		0.4%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	5.85	0.00	5.85	7.12	0.00	7.12	21.7%		21.7%
Standby (CRC) - $/kW	0.92	0.00	0.92	0.99	0.00	0.99	7.6%		7.6%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	1.59	6.19	7.78	1.48	5.42	6.90	-6.9%	-12.4%	-11.3%
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.14	1.30	1.44	0.19	2.68	2.87	35.7%	106.2%	99.3%
Supplemental demand - Summer Season									
On-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
Voltage Discount, 220 kV and above									
Facilities Related Demand (Excess FRD) - $k/W	(1.27)	0.00	(1.27)	(2.54)	0.00	(2.54)	100.0%		100.0%
Time-Related Demand - $/kW									
Backup Summer On-Peak	(1.59)	(0.02)	(1.61)	(1.48)	(0.06)	(1.54)	-6.9%	200.0%	-4.3%
Backup Winter Mid-Peak	(1.59)	(0.02)	(1.61)	(0.19)	(0.03)	(0.22)	-88.1%	50.0%	-86.3%
Supplemental Summer On-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Supplemental Winter Mid-Peak	0.00	0.00	0.00	0.00	0.00	0.00			
Energy - $/kWh	(0.00823)	(0.00064)	(0.00887)	(0.00724)	(0.00062)	(0.00786)	-12.0%	-3.1%	-11.4%
Standby (CRC) - $/kW	(0.33)	0.00	(0.33)	(0.40)	0.00	(0.40)	21.2%		21.2%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-S-B (Above 50 kV) - GF									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.03003	0.05205	0.08208	0.03011	0.05417	0.08428	0.3%	4.1%	2.7%
Mid-peak	0.03003	0.04810	0.07813	0.03011	0.05001	0.08012	0.3%	4.0%	2.5%
Off-Peak	0.03003	0.04684	0.07687	0.03011	0.04875	0.07886	0.3%	4.1%	2.6%
Winter Season									
Mid-peak	0.03003	0.07220	0.10223	0.03011	0.07331	0.10342	0.3%	1.5%	1.2%
Off-Peak	0.03003	0.04153	0.07156	0.03011	0.04204	0.07215	0.3%	1.2%	0.8%
Customer Charge - $/month	2,586.55	0.00	2,586.55	2,596.75	0.00	2,596.75	0.4%		0.4%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	10.01	0.00	10.01	10.86	0.00	10.86	8.5%		8.5%
Standby (CRC) - $/kW	1.13	0.00	1.13	1.19	0.00	1.19	5.3%		5.3%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	0.00	7.09	7.09	0.00	4.31	4.31		-39.2%	-39.2%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Supplemental demand - Summer Season									
On-Peak	0.00	16.22	16.22	0.00	11.89	11.89		-26.7%	-26.7%
Mid-Peak	0.00	5.22	5.22	0.00	3.85	3.85		-26.2%	-26.2%
Power Factor Adjustment - $/kVA	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
Voltage Discount, 220 kV and above									
Facilities Related Demand (Excess FRD) - $k/W	(5.43)	0.00	(5.43)	(6.28)	0.00	(6.28)	15.7%		15.7%
Time-Related Demand - $/kW									
Supplemental Summer on & Mid	0.00	(0.16)	(0.16)	0.00	(0.25)	(0.25)		56.3%	56.3%
Backup Summer on & Mid	0.00	(0.03)	(0.03)	0.00	(0.08)	(0.08)		166.7%	166.7%
Energy - $/kWh	0.00000	(0.00045)	(0.00045)	0.00000	(0.00046)	(0.00046)		2.2%	2.2%
Standby (CRC) - $/kW	(0.54)	0.00	(0.54)	(0.60)	0.00	(0.60)	11.1%		11.1%
TOU-8-S-Rate A (Above 50 kV) - GF									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.08455	0.21306	0.29761	0.07933	0.17443	0.25376	-6.2%	-18.1%	-14.7%
Mid-peak	0.04696	0.08317	0.13013	0.05143	0.07644	0.12787	9.5%	-8.1%	-1.7%
Off-Peak	0.03374	0.04684	0.08058	0.03580	0.04875	0.08455	6.1%	4.1%	4.9%
Winter Season									
Mid-peak	0.03652	0.07220	0.10872	0.03380	0.07331	0.10711	-7.4%	1.5%	-1.5%
Off-Peak	0.03127	0.04153	0.07280	0.03073	0.04204	0.07277	-1.7%	1.2%	0.0%
Customer Charge - $/month	2,586.55	0.00	2,586.55	2,596.75	0.00	2,596.75	0.4%		0.4%
Facilities Related Demand									
Demand Charge (Excess FRD) - $/kW	5.85	0.00	5.85	7.12	0.00	7.12	21.7%		21.7%
Standby (CRC) - $/kW	1.13	0.00	1.13	1.19	0.00	1.19	5.3%		5.3%
Time Related Demand Charge - $/kW									
Backup demand - Summer Season									
On-Peak	0.00	7.09	7.09	0.00	4.31	4.31		-39.2%	-39.2%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Supplemental demand - Summer Season									
On-Peak	0.00	0.00		0.00	0.00	0.00			
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Power Factor Adjustment - $/kVA	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
Voltage Discount, 220 kV and above									
Facilities Related Demand (Excess FRD) - $k/W	(1.27)	0.00	(1.27)	(2.54)	0.00	(2.54)	100.0%		100.0%
Time-Related Demand - $/kW									
Supplemental Summer on & Mid	0.00	0.00	0.00	0.00	0.00	0.00			
Backup Summer on & Mid	0.00	(0.03)	(0.03)	0.00	(0.08)	(0.08)		166.7%	166.7%
Energy - $/kWh	(0.00787)	0.00000	(0.00787)	(0.00724)	(0.00076)	(0.00800)	-8.0%		1.7%
Standby (CRC) - $/kW	(0.54)	0.00	(0.54)	(0.60)	0.00	(0.60)	11.1%		11.1%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
Schedule-S-D (Less than 500 kW)									
Energy Charge - $/kWh/Meter/Month - see (OAT)									
Customer Charge - $/Meter/Month - see (OAT)									
Standby (CRC) - $kW									
TOU-GS-2 (Rate D)	15.68	0.00	15.68	16.38	0.00	16.38	4.5%		4.5%
Voltage Discount, Capacity Reservation Demand - $/kW									
From 2 kV to 50 kV	(0.16)	0.00	(0.16)	(0.28)	0.00	(0.28)	75.0%		75.0%
51 kV to 219 kV	(6.72)	0.00	(6.72)	(6.00)	0.00	(6.00)	-10.7%		-10.7%
220 kV and Above	(11.66)	0.00	(11.66)	(12.36)	0.00	(12.36)	6.0%		6.0%
TOU-GS-2 (Rate E)	10.57	0.00	10.57	10.99	0.00	10.99	4.0%		4.0%
Voltage Discount, Capacity Reservation Demand - $/kW									
From 2 kV to 50 kV	(0.12)	0.00	(0.12)	(0.16)	0.00	(0.16)	33.3%		33.3%
51 kV to 219 kV	(3.78)	0.00	(3.78)	(3.39)	0.00	(3.39)	-10.3%		-10.3%
220 kV and Above	(6.55)	0.00	(6.55)	(6.97)	0.00	(6.97)	6.4%		6.4%
TOU-GS-3 (Rate D)	16.39	0.00	16.39	16.48	0.00	16.48	0.5%		0.5%
Voltage Discount, Capacity Reservation Demand - $/kW									
From 2 kV to 50 kV	(0.18)	0.00	(0.18)	(0.26)	0.00	(0.26)	44.4%		44.4%
51 kV to 219 kV	(7.49)	0.00	(7.49)	(5.60)	0.00	(5.60)	-25.2%		-25.2%
220 kV and Above	(12.27)	0.00	(12.27)	(12.36)	0.00	(12.36)	0.7%		0.7%
TOU-GS-3 (Rate E)	11.00	0.00	11.00	11.22	0.00	11.22	2.0%		2.0%
Voltage Discount, Capacity Reservation Demand - $/kW									
From 2 kV to 50 kV	(0.12)	0.00	(0.12)	(0.15)	0.00	(0.15)	25.0%		25.0%
51 kV to 219 kV	(4.20)	0.00	(4.20)	(3.22)	0.00	(3.22)	-23.3%		-23.3%
220 kV and Above	(6.88)	0.00	(6.88)	(7.10)	0.00	(7.10)	3.2%		3.2%
GS-2	15.68	0.00	15.68	16.38	0.00	16.38	4.5%		4.5%
Voltage Discount, Capacity Reservation Demand - $/kW									
From 2 kV to 50 kV	(0.16)	0.00	(0.16)	(0.28)	0.00	(0.28)	75.0%		75.0%
51 kV to 219 kV	(6.72)	0.00	(6.72)	(6.00)	0.00	(6.00)	-10.7%		-10.7%
220 kV and Above	(11.66)	0.00	(11.66)	(12.36)	0.00	(12.36)	6.0%		6.0%
Facilities Related Demand Charge - see OAT									
Demand Charge - $kW applicable to metered maximum kW demand in excess Standby									
Generation Time-related demand charge - see OAT									
Power Factor Adjustment Charge - see OAT									
Schedule-S (Less than 500 kW) - GF									
Energy Charge - $/kWh/Meter/Month - see (OAT)									
Customer Charge - $/Meter/Month - see (OAT)									
Standby (CRC) - $kW									
TOU-GS-2 (Rate B)	20.99	0.00	20.99	20.52	0.00	20.52	-2.2%		-2.2%
Voltage Discount, Capacity Reservation Demand - $/kW									
From 2 kV to 50 kV	(0.24)	0.00	(0.24)	(0.45)	0.00	(0.45)	87.5%		87.5%
51 kV to 219 kV	(8.47)	0.00	(8.47)	(9.12)	0.00	(9.12)	7.7%		7.7%
220 kV and Above	(16.97)	0.00	(16.97)	(16.50)	0.00	(16.50)	-2.8%		-2.8%
TOU-GS-2 (Rate R)	15.51	0.00	15.51	16.21	0.00	16.21	4.5%		4.5%
Voltage Discount, Capacity Reservation Demand - $/kW									
From 2 kV to 50 kV	(0.16)	0.00	(0.16)	(0.33)	0.00	(0.33)	106.3%		106.3%
51 kV to 219 kV	(5.72)	0.00	(5.72)	(6.74)	0.00	(6.74)	17.8%		17.8%
220 kV and Above	(11.49)	0.00	(11.49)	(12.19)	0.00	(12.19)	6.1%		6.1%
TOU-GS-3 (Rate B)	20.87	0.00	20.87	20.62	0.00	20.62	-1.2%		-1.2%
Voltage Discount, Capacity Reservation Demand - $/kW									
From 2 kV to 50 kV	(0.27)	0.00	(0.27)	(0.42)	0.00	(0.42)	55.6%		55.6%
51 kV to 219 kV	(8.77)	0.00	(8.77)	(8.57)	0.00	(8.57)	-2.3%		-2.3%
220 kV and Above	(16.75)	0.00	(16.75)	(16.50)	0.00	(16.50)	-1.5%		-1.5%
TOU-GS-3 (Rate R)	16.46	0.00	16.46	16.87	0.00	16.87	2.5%		2.5%
Voltage Discount, Capacity Reservation Demand - $/kW									
From 2 kV to 50 kV	(0.18)	0.00	(0.18)	(0.33)	0.00	(0.33)	83.3%		83.3%
51 kV to 219 kV	(6.48)	0.00	(6.48)	(6.63)	0.00	(6.63)	2.3%		2.3%
220 kV and Above	(12.34)	0.00	(12.34)	(12.75)	0.00	(12.75)	3.3%		3.3%
Facilities Related Demand Charge - see OAT									
Demand Charge - $kW applicable to metered maximum kW demand in excess Standby									
Generation Time-related demand charge - see OAT									
Power Factor Adjustment Charge - see OAT									

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-S-RTP (Below 2kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.04076	Variable*	Variable*	0.04549	Variable*	Variable*	11.6%		
Mid-peak	0.04076	Variable*		0.04446	Variable*	Variable*	9.1%		
Off-Peak	0.04076	Variable*		0.04425	Variable*	Variable*	8.6%		
Winter Season									
Mid-peak	0.04076	Variable*		0.04549	Variable*	Variable*	11.6%		
Off-Peak	0.04076	Variable*		0.04446	Variable*	Variable*	9.1%		
Super-Off-Peak	0.04076	Variable*		0.04386	Variable*	Variable*	7.6%		
Customer Charge - $/month	701.42	0.00	701.42	319.75	0.00	319.75	-54.4%		-54.4%
Facilities Related Demand Charge - $/kW									
Demand Charge (Excess FRD) - $/kW	17.33	0.00	17.33	18.93	0.00	18.93	9.2%		9.2%
Standby (CRC) - $/kW	16.51	0.00	16.51	16.48	0.00	16.48	-0.2%		-0.2%
Time Related Demand Charge - $/kW									
Backup demand									
Summer Season									
On-Peak	11.44	0.00	11.44	11.95	0.00	11.95	4.5%		4.5%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Winter Season									
Mid-Peak	3.31	0.00	3.31	2.12	0.00	2.12	-36.0%		-36.0%
Supplemental demand Summer Season									
On-Peak	14.86	0.00	14.86	14.57	0.00	14.57	-2.0%		-2.0%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Winter Season									
Mid-Peak	5.00	0.00	5.00	2.57	0.00	2.57	-48.6%		-48.6%
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%
TOU-8-S-RTP (From 2 kV to 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.04160	Variable*	Variable*	0.04571	Variable*	Variable*	9.9%		
Mid-peak	0.04160	Variable*		0.04481	Variable*	Variable*	7.7%		
Off-Peak	0.04160	Variable*		0.04463	Variable*	Variable*	7.3%		
Winter Season									
Mid-peak	0.04160	Variable*		0.04571	Variable*	Variable*	9.9%		
Off-Peak	0.04160	Variable*		0.04481	Variable*	Variable*	7.7%		
Super-Off-Peak	0.04160	Variable*		0.04425	Variable*	Variable*	6.4%		
Customer Charge - $/month	373.12	0.00	373.12	304.00	0.00	304.00	-18.5%		-18.5%
Facilities Related Demand Charge - $/kW									
Demand Charge (Excess FRD) - $/kW	16.97	0.00	16.97	17.98	0.00	17.98	6.0%		6.0%
Standby (CRC) - $/kW	10.86	0.00	10.86	10.04	0.00	10.04			
Time Related Demand Charge - $/kW									
Backup demand									
Summer Season									
On-Peak	8.71	0.00	8.71	10.44	0.00	10.44	19.9%		19.9%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Winter Season									
Mid-Peak	2.59	0.00	2.59	1.62	0.00	1.62	-37.5%		-37.5%
Supplemental demand Summer Season									
On-Peak	14.05	0.00	14.05	14.22	0.00	14.22	1.2%		1.2%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Winter Season									
Mid-Peak	4.58	0.00	4.58	2.55	0.00	2.55	-44.3%		-44.3%
Power Factor Adjustment - $/kVA	0.60	0.00	0.60	0.52	0.00	0.52	-13.3%		-13.3%

	October 2021 Rates			Proposed 2021 GRC Rates					
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Delivery Change	Generation Change	Total Rate Change
TOU-8-RTP (Above 50 kV)									
Energy Charge - $/kWh									
Summer Season									
On-Peak	0.03003	Variable*	Variable*	0.03011	Variable*	Variable*	0.3%		
Mid-peak	0.03003	Variable*		0.03011	Variable*	Variable*	0.3%		
Off-Peak	0.03003	Variable*		0.03011	Variable*	Variable*	0.3%		
Winter Season									
Mid-peak	0.03003	Variable*		0.03011	Variable*	Variable*	0.3%		
Off-Peak	0.03003	Variable*		0.03011	Variable*	Variable*	0.3%		
Super-Off-Peak	0.03003	Variable*		0.03011	Variable*	Variable*	0.3%		
Customer Charge - $/month	2,586.55	0.00	2,586.55	2,596.75	0.00	2,596.75	0.4%		0.4%
Facilities Related Demand Charge - $/kW									
Demand Charge (Excess FRD) - $/kW	7.40	0.00	7.40	8.97	0.00	8.97	21.2%		21.2%
Standby (CRC) - $/kW	0.92	0.00	0.92	0.99	0.00	0.99	7.6%		7.6%
Time Related Demand Charge - $/kW									
Backup demand									
Summer Season									
On-Peak	1.59	0.00	1.59	1.48	0.00	1.48	-6.9%		-6.9%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.14	0.00	0.14	0.19	0.00	0.19			
Supplemental demand Summer Season									
On-Peak	6.65	0.00	6.65	4.90	0.00	4.90	-26.3%		-26.3%
Mid-Peak	0.00	0.00		0.00	0.00	0.00			
Winter Season									
Mid-Peak	0.77	0.00	0.77	0.56	0.00	0.56			
Power Factor Adjustment - $/kVA	0.54	0.00	0.54	0.66	0.00	0.66	22.2%		22.2%
Voltage Discount, 220 kV and above									
Facilities Related Demand (Excess FRD) - $k/W	(2.93)	0.00	(2.93)	(4.39)	0.00	(4.39)	49.8%		49.8%
Time-Related Demand - $/kW									
Backup Summer On-Peak	(0.55)	0.00	(0.55)	(1.48)	0.00	(1.48)	169.1%		169.1%
Backup Winter Mid-Peak	(0.55)	0.00	(0.55)	(0.19)	0.00	(0.19)	-65.5%		-65.5%
Supplemental Summer On-Peak	(2.89)	0.00	(2.89)	(4.90)	0.00	(4.90)	69.6%		69.6%
Supplemental Winter Mid-Peak	(2.89)	0.00	(2.89)	(0.56)	0.00	(0.56)	-80.6%		-80.6%
Energy - $/kWh	0.00000	(0.00064)	(0.00064)	0.00000	(0.00062)	(0.00062)		-3.1%	-3.1%
Standby (CRC) - $/kW	(0.33)	0.00	(0.33)	(0.40)	0.00	(0.40)	21.2%		21.2%
Optional CPP rider < 200 kW									
CPP Event Energy Charge - $/kWh									
GS-2-TOU	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer Non-Event Demand Credit - $/kW									
GS-2-TOU (On-Peak Dmand)	0.00	(6.85)	(6.85)	0.00	(6.85)	(6.85)		0.0%	0.0%
Default CPP rider > 200 kW									
TOU-GS-3									
2 p.m. to 6 p.m CPP Event Energy Charge - $/kWh	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer On Peak Demand Credit - $/kW	0.00000	(7.55)	(7.55)	0.00000	(7.55)	(7.55)		0.0%	0.0%
TOU-8-SEC									
2 p.m. to 6 p.m CPP Event Energy Charge - $/kWh	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer On Peak Demand Credit - $/kW	0.00000	(8.22)	(8.22)	0.00000	(8.22)	(8.22)		0.0%	0.0%
TOU-8-PRI									
2 p.m. to 6 p.m CPP Event Energy Charge - $/kWh	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer On Peak Demand Credit - $/kW	0.00000	(8.52)	(8.52)	0.00000	(8.52)	(8.52)		0.0%	0.0%
TOU-8-SUB									
2 p.m. to 6 p.m CPP Event Energy Charge - $/kWh	0.00000	0.80000	0.80000	0.00000	0.80000	0.80000		0.0%	0.0%
Summer On Peak Demand Credit - $/kW	0.00000	(8.44)	(8.44)	0.00000	(8.44)	(8.44)		0.0%	0.0%