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January 9, 2025

California Energy Commission

Re: Docket No. 23-LMS-01
1516 Ninth Street
Sacramento, CA 95814-5512
docket@energy.ca.gov

Re: Southern California Edison Company's Revised Plan to Comply with the California Energy Commission's Load Management Standards, Sections 1621 and 1623

Dear Commissioners:

Pursuant to the California Energy Commission's (CEC) Load Management Standards (LMS) and feedback received from the CEC in response to the initial version of this compliance plan, Southern California Edison (SCE) is hereby submitting its LMS compliance plan (Compliance Plan), with revisions,[1] for review and approval, as required by Title 20, California Code of Regulations (CCR) Section 1621(d),[2] which requires California's large investor-owned utilities (IOUs) to comply as follows:

> *"(1) Each Large IOU shall submit a plan to comply with Sections 1621 and 1623 of this article to the Executive Director no later than six (6) months after April 1, 2023."*

The LMS amendments require IOUs to first submit their compliance plans to the CEC to demonstrate compliance with the requirements of sections 1621 and 1623 by October 1, 2023,[3] and then apply to their rate-approving bodies (i.e., California Public Utilities Commission (CPUC) and Federal Energy Regulatory Commission (FERC)) for approval of at least one optional hourly marginal cost-based (i.e., Real-Time Pricing (RTP)) rate <u>or</u> program for every customer[4] in each customer class by January 2025, and offer such rate or program to customers by January 2027. This marginal cost-based rate must include a marginal cost-based hourly or

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[1] The revisions provided herein address issues in SCE's original LMS Compliance Plan identified in CEC Staff Letter *Division Request for Revisions of SCE LMS Compliance Plan*, dated April 15, 2024. Two specific issues identified by Staff are identified in this revision request: (1) 1623(a): Marginal rate design and application and (2) 1623(d)(1)-(2): List of alternative cost-effective, LMS-compliant programs and rates.

[2] The LMS are codified in California Code of Regulations, Title 20, Division 2, Chapter 4, Article 5, Sections 1621-1625. The amended regulations in section 1621(d) specifically applies to California's IOUs (Pacific Gas and Electric, San Diego Gas and Electric, and Southern California Edison).

[3] In accordance with 20 C.C.R. section 1003, "…where a LMS compliance date falls on a weekend, holiday, or other day when the CEC offices are closed, regulated parties may comply with the regulatory requirement on the next business day." Per June 22, 2023 CEC notice: https://efiling.energy.ca.gov/GetDocument.aspx?tn=250797&DocumentContentId=85690

[4] *See* SCE's Application for Approval of Marginal Cost-Based Dynamic Pricing Rates in Compliance with Decision 22-10-022 and Load Management Standards, SCE-01 at pp. 9-10. In general, customers participating on Non-TOU, Tiered, Master Metered, TC-1, Streetlights, WTR, RES-BCT, NEM-V, MASH-VNM, SOMAH, NEM-A, NBT-A, SPESD, Maritime Entities (ME), and Legacy Rates are not eligible to take service on the Proposed Rates.

sub-hourly generation energy and capacity (import only, i.e., delivered to the customer) dynamic rate component, as well as marginal cost-based hourly or sub-hourly distribution and transmission dynamic rate components.  If LMS-compliant, marginal cost-based rates are not adopted by the rate-approving bodies in time to be available to each customer class by January 2027, alternative cost-effective load flexibility programs must be made available to the customers to participate.

SCE's plan for complying with the requirements of Sections 1621 and 1623 is organized as follows:[5]

1. Marginal rate design and application – Section 1623(a)
2. Time-dependent rate submission to Market Informed Demand Automation Server (MIDAS) via MIDAS Application Programming Interface (API) – Section 1623(b)
3. Plan to provide Rate Identification Numbers (RINs) on customer billing statements and online account using both text and QR code – Section 1623(c)(4)
4. Plans and current participation in the development of Single Statewide RIN Access Tool – Section 1623(c)(1)-(3)
5. List of alternative cost-effective, LMS-compliant programs and rates – Section 1623(d)(1)-(2)
6. Plan for conducting public information program – Section 1623(d)(3)

The multi-part Compliance Plan is structured to align the LMS with the ongoing CPUC Demand Flexibility OIR (DFOIR) proceeding (R.22-07-005).  Additionally, since Section 1623 includes dynamic transmission rates, the plan includes steps necessary to receive approval for time-variant transmission and associated revenue allocation to reflect the time dependency of the new rate designs.  SCE anticipates that it will submit a modification to this plan if the CPUC's Demand Flexibility OIR proceeding timeline and scope are altered as a result of the April 24, 2024 ALJ Ruling issued in that proceeding.

## 1. <u>Marginal rate design and application</u>

SCE currently offers marginal cost-based rate designs that include generation and distribution rate components to all customer classes.  Designing rates based on marginal costs that include the time-dependent relationships associated with SCE's cost of service has been a long-standing policy of the CPUC and practiced by SCE.  Transmission rates, however, reflect embedded cost rate design consistent with long-standing FERC policies regarding revenue allocation and rate design.  In this section, SCE will discuss how we plan to bridge the gap between marginal versus embedded costs rate design to ensure the goals of the LMS are reached.

Section 1623(a) states: *"Total marginal cost shall be calculated as the sum of the marginal energy cost, the marginal capacity cost (generation, transmission, and distribution), and any other appropriate time and location dependent marginal costs, including the locational*

[5] SCE has organized its Compliance Plan to follow a guidance structure provided by CEC Staff in a document entitled "*Compliance Assistance for LMS Compliance Plan Submittals*" in LMS Implementation Docket 23-LMS-01, issued on July 14, 2023.

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*marginal cost of associated greenhouse gas emissions, on a time interval of no more than one hour."*

SCE currently designs the distribution and generation capacity components of current tariff schedule rates in a manner consistent with Section 1623(a), where the distribution and generation capacity components are time-dependent, reflecting the variations in the probability and value of system reliability. Distribution capacity marginal costs reflect distribution system constraints that exist in the diurnal loading and unloading of the distribution system as customers charge or discharge Distributed Energy Resources (DERs), cycle appliances and equipment, and export solar energy to the grid. Each of these applications has a unique effect on the level of distribution capacity required for safe and reliable service, and thus this pattern is reflected in SCE's distribution capacity marginal costs.

Similarly, SCE's generation capacity marginal costs reflect the time-dependency associated with ramp capacity resource constraints that occur when supply from renewable resource, primarily solar, decreases as the sun sets as well as capacity constraints associated with meeting peak loads that can occur concurrent with, or after, the ramp constraint. While Greenhouse Gas (GHG) costs are currently not considered a marginal cost, the cost of GHG, as a related fuel and purchase power cost, is embedded in SCE's generation rate. GHG costs are applied to rates based on the time-dependent pattern reflected in generation energy and capacity marginal costs. To the extent the GHG related marginal costs are not correlated with the cost pattern exhibited by the sum of energy and capacity related cost, SCE will explore methods of determining a separate GHG marginal cost component. SCE plans to continue applying time-dependent distribution and generation capacity marginal cost rate design in its RTP proposals for the LMS requirements.

The two areas where SCE will need to adjust its current methodologies include: 1) a transition from production model-based marginal energy costs to hourly locational marginal energy cost pricing associated with our local balancing authority and 2) development of marginal cost-based transmission rates, which are currently developed based on embedded costs.

SCE is currently conducting the CalFUSE Dynamic Rate Pilot (SCE Flexible Pricing Rate Pilot) with pricing that includes hourly distribution and generation components. The generation component consists of a capacity price function with day-ahead California Independent System Operator (CAISO) energy as a passthrough energy price. SCE expects to gain meaningful experience and knowledge through the pilot to inform an eventual full-scale RTP rate design incorporating day-ahead CAISO Default Load Aggregation Point (DLAP) pricing to meet the LMS requirements. SCE's Flexible Pricing Rate Pilot will yield valuable information regarding the systems, data transfer architecture, and operational processes needed to ensure a favorable customer experience and cost-effective implementation. Currently, SCE is scheduled to run the pilot through the end of 2024, with a preliminary study report expected in the fall of 2024. Furthermore, SCE intends to file a standalone rate design application with the CPUC in June 2024 for a Large Industrial Class (LIC) dynamic pricing rate reflecting the same hourly pricing signals required under the LMS, including passthrough DLAP pricing. In developing and implementing this new rate option, SCE can begin to develop an IT foundation that can be applied and modified for other dynamic pricing rates in the future. SCE's LMS-compliant full-scale RTP rate will use CAISO DLAP day-ahead pricing in lieu of production modeling results.

SCE's transmission retail rate designs have not evolved to the same level as distribution and generation rates. The effects of increasing renewable supply and the shift to GHG reducing technologies on the demand side are not reflected in the current transmission rates. This is partially due to the underlying cost basis for transmission rates which does not account for time-dependent drivers of utility costs as is the case with CPUC jurisdictional marginal cost rate design. The embedded cost methodology used in transmission rates effectively allocates average cost of service to the various rate classes based on their respective contribution to monthly system coincident peak demand (i.e., a 12 coincident peak (12-CP) allocation) and then applies the allocated cost to rate structures governed by local jurisdictions.[6] To bridge this methodological difference, SCE will perform a transmission marginal cost study, to be filed with the CPUC, that will determine the level and pattern of time-dependency present in transmission service using a similar methodology as the one used for distribution marginal costs. While this filing at the CPUC will not establish the final hourly transmission rates to meet the LMS requirement, the filing will establish the relationship between transmission cost components that are fixed (i.e., non-time-dependent) and those that are variable (i.e., time-dependent). The transmission marginal cost study will also reveal the average diurnal cost pattern associated with the variable rate component. With the relationship between fixed and variable rate parameters established, SCE will file an application with the FERC for retail RTP rates reflecting the established fixed and variable cost parameters. Pursuant to Title 18 of the Code of Federal Regulations governing Single-Issue 205 Applications filed at the FERC, the Single-Issue Application must be filed "not less than sixty days nor more than one hundred-twenty days"[7] before the scheduled implementation date. Because SCE's expected implementation will be on October 1, 2027, the FERC application will be filed no sooner than June 3, 2027.

SCE will maintain the current 12-CP allocation in its FERC filing. Over time, as SCE gains more experience with hourly transmission rates, SCE may change the allocation methodology to also reflect fixed and variable cost drivers. The approach of filing at both the CPUC and FERC has been used by SCE where rate structures adopted by the CPUC also determined the associated transmission rate structure. The use of this approach allows for the most expedient implementation as the FERC process is disposed within the same timeline required for rate implementation.

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[6] *See* SCE's FERC-approved Formula Rate Protocols, Section 8.d. (Attachment 1 to Appendix IX of the Transmission Owner Tariff). Attachment 1 may be accessed via SCE's website at: https://www.sce.com/regulatory/open-access-information

[7] Title 18 of the Code of Federal Regulations, Section 35.3(a)(1).

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**a) Rate design and application timeline**

The Joint IOU Working Group 1 Report (The Working Group Report), filed as part of the CPUC's DFOIR, discusses the timing of pilots and other procedural requirements.[8] As discussed in the report, SCE has already made a version of RTP rates, which include marginal costs-based distribution and generation rate components, available to most customer classes through its SCE Flexible Pricing Rate Pilot. The pilot is expected to yield data critical to the development of the LMS-compliant RTP rate, its associated customer programs, and the delivery and messaging strategies to ensure meaningful levels of participation on hourly pricing programs. The Working Group Report also discusses the misalignment between the timelines associated with 1) the availability of pilot results to inform the full-scale RTP rate design, 2) the CPUC and FERC regulatory processes necessary to gain approval for rate design proposals in both regulatory jurisdictions, and 3) the LMS schedule for full implementation of the LMS-compliant RTP rates.[9] Because of this misalignment, SCE is likely to request an exemption under the provision of 20 CCR § 1621 as the CPUC's DFOIR unfolds.

As illustrated in **Figure 1** below, the LMS timeline calls for SCE to file a proposal for full-scale RTP rate designs by January 1, 2025, and then offer full-scale RTP rates to all rate classes by January 1, 2027. Initial CPUC guidance regarding full-scale RTP rate design in the DFOIR, which includes the Flexible Pricing Rate Pilot, is expected in the third or fourth quarter of 2024. Given the recent extensions of the RTP pilots, final guidance may not be received until the second quarter of 2028. To offer full-scale RTP by January 1, 2025, SCE plans to develop a full-scale RTP rate design prior to receiving final guidance from the CPUC, by leveraging the LIC dynamic pricing rate. The design of the full-scale RTP rate can take approximately 6-months. Should the CPUC's guidance require rate design elements or procedures that are not reflected in SCE's LIC based rate design, SCE will evaluate the incremental time required to address the deficiency and potentially seek an exception from either the CPUC or the CEC related to the rate design requirements or the timing of the January 1, 2025 filing, respectively.

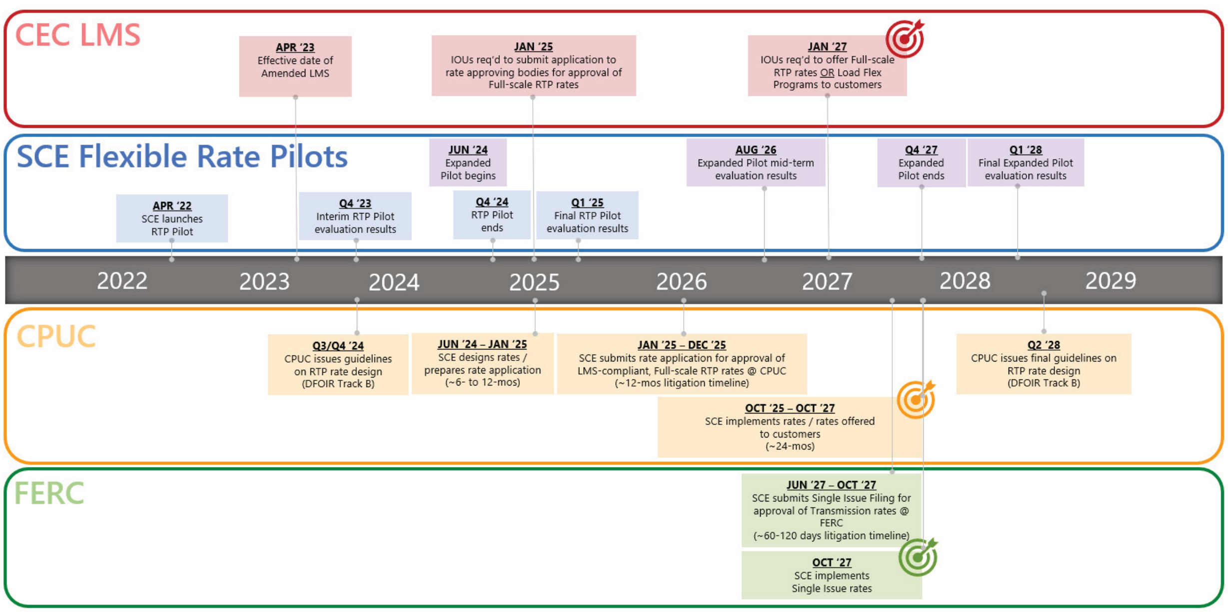
**Figure 1** also illustrates the timeline for the rate design application at the FERC. This step is omitted entirely in the LMS schedule, however, is necessary to meet the requirements for a marginal cost-based transmission rate. It is important to note that the process for receiving FERC approval can be completed within the timeline needed for the CPUC process and implementation of rates. SCE's approach will not add incrementally to the schedule. The transmission rate design process does involve an application at the CPUC to litigate transmission marginal costs drivers that establish the relationships between variable and fixed charges as well as time-dependency. Because of the long-standing policy of embedded cost rate design at the

[8] The Joint IOU Working Group 1 (Rate Design) proposals will be included in the Demand Flexibility Track B Working Report to be filed on October 11, 2023 in the R.22-07-005 proceeding docket.

[9] SCE notes that the timeline, as set forth, in The Working Group Report estimates a minimum of 12-months required to implement LMS-compliant, full-scale RTP rates. The Joint IOUs also stated "…an alternate timeline to implement LMS-compliant full-scale RTP rates [will be proposed] in their October 2023 LMS Compliance Plans." As such, SCE would like to update this estimate to reflect the rates implementation timing more accurately to 24-30 months.

FERC, it is likely the submission of a marginal cost proposal directly to the FERC would take more time to resolve than the path laid out in this Compliance Plan, as SCE would need to first reach a resolution on embedded versus marginal costs rate design before reaching a resolution on the rates themselves. Rather than file such a proposal at the FERC, SCE will therefore file a transmission marginal costs study with the CPUC for the purpose of establishing the relation between fixed and variable cost components in the same rate application that will include distribution and generation marginal cost-based dynamic rates. Once the transmission retail rate framework (i.e., marginal cost drivers and time dependencies for pricing) has been approved by the CPUC, SCE will file a Single-Issue application with FERC for final approval of the transmission retail rates using the FERC authorized revenue allocation across rate classes and the FERC authorized revenue requirements. SCE has used this two-step Single-Issue approach in previous proceedings that involve the introduction of new marginal costs-based rate offerings in a CPUC proceeding where the design of transmission retail rates are also affected.[10] The FERC requires that these Single-Issue applications be filed no sooner than 6-months prior to the implementation date, which comfortably falls within the time needed for SCE to implement rates in its billing system. The timeline in **Figure 1** reflects this requirement.

**Figure 1: CEC LMS / SCE Flexible Rate Pilot / CPUC / FERC Regulatory Timeline**




## b) Marginal rate design, rate application, and current progress resource commitment

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[10] *See* FERC Docket ER19-374 to establish three new, commercial EV rate schedules for six CPUC rate classes. FERC Docket ER13-1190 in 2013, to adjust retail transmission rates associated with a reclassification of standby customers, a reclassification of pumping and agriculture customers, and the introduction of a new small commercial rate option. In both cases, the rate structures were approved by the CPUC prior to gaining approval at the FERC through a single-issue Section 205 filing.

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The process of rate design and the preparation of an application for submission to a regulatory body involves several disciplines with varied skillsets. This is because marginal cost-based rates are rooted in the fundamental drivers of utility costs of service and each rate class's contribution to these drivers in addition to the unit marginal cost associated with infrastructure and other utility functions. Each rate class's proportional contribution to the utility's cost of service is determined by the number of customers within the class, the load pattern (i.e., energy and demand) exhibited by the class at various times of the day, and the unit marginal cost associated with transmission and distribution infrastructure and for generation, hourly market prices for energy and long-run marginal costs for capacity resources. Once the proportional contribution of each class has been determined, the authorized revenue requirement is allocated across the rate classes to assign an amount of authorized revenue to be collected from each class. The final step is the rate setting process where the retail rates are set to recover each rate class's respective allocated revenue requirement. This is done by scaling the marginal cost rates to a level that recovers the allocated authorized revenue requirement.

The multiple steps described above are performed by various teams within the Pricing Design and Research (PD&R) organization. These teams include Load Research, Marginal Costs, Rate Design, and Rate Operations. With more complex rate designs, such as RTP, the teams may work in parallel to develop and test the rate designs. Overall case management of the application also resides within PD&R.

It is difficult to assess future resource commitments for PD&R absent the CPUC's guidance on the specific structure and scope of the full-scale RTP rate design. An immediate full rollout of dynamic time-dependent rates, including transactive elements vetted in the CPUC Staff's CalFUSE framework, to all customer classes would have a measurably different resource commitment compared to a rollout that incorporates MIDAS for certain customer segments, and reserves transactive RTP for a limited number of larger, more energy knowledgeable customers.

The current PD&R resource commitments to perform the tasks described above are listed in **Table *1*** below. The resources identified in the Load Research, Rate Design, and Rate Operations teams are currently involved with RTP rate design through the CEC's MIDAS/LMS proceedings as well as the CPUC's DFOIR to include the SCE Flexible Pricing Rate Pilots.

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**Table 1: Current PD&R Resource Commitment and Activity by Year**[11]

| | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|
| **PD&R Team** | **MIDAS Uploads, Demand Flex OIR & Flexible Pricing Rate Pilot** | **MIDAS Uploads, Demand Flex OIR, Flexible Pricing Rate Pilots & CPUC RTP Application** | **MIDAS Uploads, Demand Flex OIR, Expanded Flexible Pricing Rate Pilot & CPUC RTP Application** | **MIDAS Uploads, Demand Flex OIR, Expanded Flexible Pricing Rate Pilot, CPUC RTP Application & FERC RTP Application** |
| Load Research | 1 | 1 | 1 | 1 |
| Marginal Costs | 0 | 1 | 1 | 1 |
| Rate Design | 2 | 2 | 2 | 2 |
| Rate Operations | 1 | 1 | 1 | 1 |
| **Total** | **4** | **5** | **5** | **5** |

c) **Marginal cost-based rate design progress. Identify potential marginal cost rates and evaluate their compliance with 1623(a)(1)**

i. **Discussion of rate design intentions, considerations, and trade-offs**

In accordance with the CPUC Assigned Commissioner's Scoping Memo and Ruling in Track B of the DFOIR, SCE along with Pacific Gas & Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) (Joint IOUs) submitted a joint proposal for Load Flexibility Rates, including RTP Rate Design, as an outcome of a host of discussions stemming from Working Group 1 meetings held from January through August 2023. As required by the Assigned Commissioner's Ruling in that proceeding, the joint proposal presented guidance and a Stepping-Stones Pathway that the CPUC should adopt for dynamic rate design in its DFOIR Phase 1 Track B decision expected in Q1 of 2024.

The Stepping-Stones approach leads the discussion as a developmental pathway that seeks to deploy a suite of time-dependent rates that can be leveraged by our customer groups in a manner that presents customer groups the optionality of enrolling in this suite of time-dependent rates based on the diversity in rate-understandability and energy proficiency that can exist across different customer groups and by customers within each customer group. Time-dependent rates considered in the Stepping-Stones approach include Time-of-use (TOU), Critical Peak Pricing (CPP), Variable Peak Pricing (VPP), and more complex time-dependent rates as envisioned by the CPUC Staff's CalFUSE framework and included in regulations proposed in accordance with the CEC's Load Management Standards.

[11] The resource commitments presented here are for Pricing Design and Research only. As mentioned later in section 1e, additional resources to support the launch of these rates will be needed, and that resource amount cannot be estimated until the structure and design of the rate is determined.

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In presenting this proposal to the CPUC, the Joint IOUs hinged to the guidepost of developing a pathway to implementing the *most effective demand flexibility rates at least cost with the best possible customer experience in mind*. More specifically,

> (1) The IOUs leveraged insights on customer experience gained through customer research studies conducted by both SCE and PG&E with the notion that continued pilots that test customer experience are critical inputs to rate designs that will be developed for broader deployment of time-dependent dynamic rates across customer groups.
>
> (2) The IOUs posited that *Effectiveness* is a trade-off between (a) the complexity of a rate design that can elicit larger load response per customer and (b) the number of customers subscribed to the rate to elicit load response sufficiently large to have a meaningful impact on the Grid. (3) The IOUs also considered the cost to implement a rate design in each IOU's billing system that includes the needed system interfaces, processes, and the ecosystem to enable a seamless transition to time-dependent dynamic rates while also broadening the scope and depth of customer engagement in a way that enhances the overall customer experience on such rates.

**ii. Frequency**

It is difficult to assess future compliance frequency absent the CPUC's guidance on the specific structure, and the scope of the dynamic RTP rate design. SCE expects to manage compliance frequency using a three-step approach – one compliance filing aligned with Phase 2 of SCE's General Rate Case (GRC) for marginal cost determinations adopted in that proceeding, a second potential compliance filing aligned with SCE's Energy Resource Recovery Account (ERRA) proceedings to account for CAISO influenced pricing parameters, and a third to periodically adjust transmission rates. SCE will also seek to validate customer participation and experience on the most effective deployment of the Stepping-Stones approach articulated in the CPUC's DFOIR, in an appropriate venue. SCE has not yet determined the appropriateness or need for a potential compliance filing where SCE would align with its ERRA implementation filing but will assess this element of the plan as SCE receives guidance from the CPUC in the CPUC's DFOIR.

**iii. Proposed details about marginal capacity costs (Generation, Distribution, and Transmission)**

SCE's design of Capacity Prices as reflected in time-dependent dynamic rates that are tied to Grid conditions (both for *Generation* and for *Distribution)*, should be based on SCE's GRC-adopted marginal cost methodology.[12] Current retail rate design for the *Transmission* includes FERC jurisdictional transmission costs on an embedded basis (not marginal cost basis), and is vetted in SCE's Transmission Revenue Formula Rate Proceeding filed at the FERC.

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[12] SCE's Phase 2 of the 2021 GRC presents analysis and discussion on the assignment of Generation Capacity Peak and Ramp Capacity Costs and Distribution Capacity Peak and Grid as currently included in the design of Time-Of-Use rates. Time of use rates aggregate hourly marginal costs into defined time-of-use periods. SCE has three time of use periods for each season - Summer and Winter.

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*Generation Capacity Marginal Costs:* Generally, capacity prices should tie to generation capacity system constraints that are driven by increasing levels of System (or Net) load, demand/supply imbalances from constrained generation capacity resources during certain hours of the year, including potential imbalances that can occur as a result of significant ramps of what is colloquially described as the *Duck Curve* (when the System Net Load ramps to meet Net Load Peak during significant ramp hours of the year), or the confluence of factors that can lead to the prospect of higher generation capacity costs on the margin. In addition, Generation Capacity Prices can reflect the likelihood of Alerts, Warnings, and Emergencies (AWE) issued by the CAISO. Generation Capacity Prices should include loss factors that may vary depending on customer service voltage or other factors. During the early stages of Time Dependent Dynamic Rates deployment, SCE expects to initially calibrate Generation Capacity prices on a day-ahead basis with the possible intent of eventually calibrating pricing for Capacity constraints based on a day-of basis, using the realized load response achieved through the conveyance of day-ahead pricing.

*Distribution Capacity Marginal Costs*: Consistent with the Stepping-Stones approach, early-stage opt-in time-dependent dynamic rates should be deployed without a dynamic distribution component, or with a non-locational, system wide, distribution marginal cost-based price signal, until time-dependent dynamic rates become more mature. Because of SCE's large service area of approximately 50,000 square miles, investments in distribution capacity and the ensuing utilization of such capacity can differ across different regions. In addition, the lumpiness of capacity investments on the distribution system can be pronounced as one traverses the entire topography of the system from the point of interface with the CAISO transmission system all the way down to the localized feeders, radials, and secondaries serving customer specific load across our service area. This lumpiness, complemented by the evolution of load tied to the progressive evolution of demographics across SCE's service area, results in varying time-dependent peaks and capacity constraints across the Distribution Grid. This variation can be observed within a layer of distribution topography, say circuits, as well as across the different topographical layers of the system that include Distribution Substations, Sub-transmission Substations, and Sub-transmission circuits.[13]

Traditional TOU rates include both time-dependent and non-time components of distribution costs on a system-wide assignment basis and for the purposes of designing time-dependent dynamic rates, SCE intends to only use the time-dependent components of distribution costs as elaborated in the GRC.[14] In the DFOIR, the Joint IOUs, including SCE, have proposed the need for expanded or additional pilots to better vet the design and implementation of time-dependent dynamic distribution rates that are tied to localized distribution grid conditions while offering the optionality of including a system wide distribution

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[13] Distribution Circuits and Substations typically include voltage levels from 2 kV to 33 kV, and Sub-transmission Circuits and Substations typically include voltage levels from 50 kV up to voltage levels deemed FERC jurisdictional or considered part of the CAISO Transmission network.

[14] As articulated in the GRC, SCE has drawn on a balanced assignment of distribution marginal costs as used in the design of retail rates to convey as a price, the dual functionality of the Distribution Grid serving as a Peak Capacity Resource and a Grid Capacity resource, the latter being driven by the enhanced geo-spatial connectivity of the system as a network across the described topology of the Distribution Grid.

price signal that reflects time-varying components of distribution marginal cost in the early-stage deployment of time-dependent dynamic rates.

*Transmission Capacity Marginal Costs*: Current retail rate design for the *Transmission Capacity* includes FERC jurisdictional transmission costs on an embedded costs basis that is vetted in SCE's Transmission Revenue Formula Rate Proceeding filed at the FERC. Additionally, retail transmission rates are designed to be non-time differentiated and therefore, introducing TOU transmission rates for FERC approval should be the first step of a broader evolution of time-dependent dynamic transmission rates in support of load management goals in California. Separately, CAISO prices include short-run transmission congestion prices on the transmission system. In the DFOIR, joint IOUs, including SCE, proposed studies to determine whether, and how, to incorporate dynamic or hourly (or sub-hourly) transmission costs into dynamic rate schedules in the future. Until such studies that examine dynamic transmission pricing are complete, it is premature to assess, in this Compliance Plan, the methodology, design, and effectiveness of including hourly (or sub-hourly) dynamic transmission prices in time-dependent dynamic rates, all of which will have to be presented, discussed, and vetted in both CPUC and FERC jurisdictional proceedings as discussed above.

**iv. Proposed details about marginal energy costs**

Generation energy prices should reflect Day-Ahead prices at the DLAP for a load serving entity (LSE) where available, or other Day-Ahead marginal costs actually incurred by the LSE. Because a large proportion of procured energy in the CAISO market clears in the Day-Ahead market, and day-ahead prices are generally easier for customers to plan load response, when compared to day-of prices, SCE will reflect CAISO Day-Ahead DLAP prices for its time-dependent dynamic rate energy component. Based on the experience from initial deployment of time-dependent dynamic rates in the CalFUSE Dynamic Rate Pilot, SCE may consider as a potential evolution of the deployment of such rates, the potential of day-of and/or sub-hourly pricing. Such considerations will need to hinge on realized feedback from customer participation on time-dependent dynamic rates, as well as the system interfaces, programmatic processes, and data requirements needed to stand-up the broader deployment of such day-of or sub-hourly prices for SCE's customer groups.

**v. Proposed details about other marginal costs**

In Phase 2 of SCE's 2021 GRC,[15] as filed at the CPUC, SCE presents proposals and discussion on the inclusion of both short-run and long-run marginal costs in the design of retail rates and revenue allocation across different customer groups. Short-run marginal costs typically center on Generation Energy marginal costs ($/kWh) and Customer Engagement marginal costs ($/customer-day/month). Long-run marginal costs typically center on Generation Capacity marginal costs ($/kW-yr.), Distribution Capacity marginal costs ($/kW-yr.), and the marginal cost of customer access to the distribution grid ($/customer-yr.). In the GRC Phase 2, SCE

[15] Information and documents for Phase 2 of SCE's 2021 GRC (A.20-10-012) proceeding may be accessed via the CPUC's website at:
https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:A2010012

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presents methodologies to derive the unit marginal costs for each of the cost components described here and then uses the disposition of such costs to allocate revenues between customer groups and design retail rates for each customer group. In the GRC, for Generation, SCE also presents an assignment for Generation Capacity marginal costs between time-dependent Generation Peak Capacity marginal costs and time-dependent Generation Ramp Capacity marginal costs. For Distribution, SCE presents an assignment for Distribution Capacity marginal costs between time-dependent Distribution Peak Capacity marginal costs and non-time-dependent Distribution Capacity Grid Costs. Time-dependent costs, as described here, are used to design retail rate components that vary by time-of-use and should similarly be used in designing time-dependent, marginal cost based dynamic rates as directed by the CEC's LMS. As presented in SCE's GRC, all non-time dependent costs should be excluded from time-dependent marginal cost based dynamic rates. Additionally, in the DFOIR, the joint IOUs, including SCE, have proposed that marginal cost scaling factors that ensure retail rates recover CPUC authorized revenues can differ by IOU and should be tested further to determine the optimal recovery mechanism for inclusion or exclusion from the time-dependent dynamic rate.

**vi. Customer class(es)**

For the purposes of designing retail rates, SCE aggregates customers into different customer groups based on their inherent end-use of electricity. Below is a list of customer classes in **Table *2***.

**Table 2: SCE Customer Classes**

| Customer Class | Description |
|---|---|
| Domestic Non-CARE | Residential Non-CARE (Includes FERA) |
| Domestic CARE | Residential CARE |
| TOU-GS-1 | Small Commercial - Metered load below 20 kW |
| TOU-GS-2 | Medium Commercial - Metered Load between 20 kW to 200 kW |
| TC-1 | Traffic Control |
| TOU-GS-3 | Medium Commercial - Metered Load between 200 kW to 500 kW |
| TOU-8-SEC | Large Commercial and Industrial - Secondary - Metered Load above 500 kW<br>Service Voltage less than 2 kV |
| TOU-8-PRI | Large Commercial and Industrial - Primary - Metered Load above 500 kW<br>Service Voltage between 2 kV and 50 kV |
| TOU-8-SUB | Large Commercial and Industrial - Sub-transmission - Metered Load above 500 kW<br>Service Voltage above 50 kV |
| TOU-8-Standby-SEC | Large Commercial and Industrial - Secondary - Standby - Metered Load above 500 kW<br>Service Voltage less than 2 kV |
| TOU-8-Standby-PRI | Large Commercial and Industrial - Primary - Standby - Metered Load above 500 kW<br>Service Voltage between 2 kV and 50 kV |
| TOU-8-Standby-SUB | Large Commercial and Industrial - Sub-transmission - Standby - Metered Load above 500 kW<br>Service Voltage above 50 kV |

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| Customer Class | Description |
|---|---|
| TOU-PA-2 | Agricultural and Pumping - Metered load below 200 kW |
| TOU-PA-3 | Agricultural and Pumping - Metered load between 200 kW to 500 kW |
| LS-1 | Street / Highway Lighting - SCE Owned - Unmetered - LS-1 |
| LS-2 | Street / Highway Lighting - Customer Owned, Unmetered - LS-2 |
| LS-3 | Street / Highway Lighting - Customer Owned, Metered - LS-3 |
| DWL | Residential Walkway Lighting - Unmetered - DWL (Closed to new installations) |
| OL-1 | Outdoor Area Lighting - Unmetered - OL-1 |
| AL-2 | Outdoor Area Lighting - Metered - AL-2 |

**d) Internal infrastructure development in support of marginal cost rates adoption**

SCE has been an active participant in the CPUC's DFOIR working group process which was formed to discuss and collect proposals for Demand Flexible Rate Designs (Working Group 1) and supporting tools and processes (Working Group 2). Working Group 2 discussed topics relating to a price calculation system or "price machine" and how one would interact with other systems, such as a subscription manager, transactive system, price portal and the distribution and generation provider billing systems.[16] SCE, jointly with PG&E and SDG&E, provided a proposal in the Working Group 2 Report which suggests recommendations for CPUC guidance for future applications for development and/or adoption of these systems.[17] The Joint IOU proposal generally built upon the ED Staff proposal but included considerations for additional optionality for the number and location of systems such as the price machine and highlighted that systems such as the subscription manager and transactive system may be optional and/or built in a later phase as rates with these additional features are added. The Joint IOU proposal currently recommends MIDAS be used as the price portal and is open to other configurations as things evolve in this space. SCE anticipates that the CPUC will consider this proposal, as well as other proposals, and adopt guidance for future applications for demand flexibility rate design. It is in those applications that SCE will provide the specific details of new systems and process and/or modifications to existing billing systems that will be needed to facilitate its proposed marginal cost rate design as well as the resource needs anticipated to support such work.

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[16] CPUC Staff Proposal on Advanced Demand Flexibility Management introduces the concept of a flexible "Price Machine" to accommodate the pricing policies of different LSEs and UDCs. As noted, the price machine could be a cloud-based IT platform to which the LSEs and UDCs upload their respective rates designed to recover the cost of generation, distribution, and transmission services and other fixed costs), along with the [price] machine receiving the dynamic LMPs from CAISO representing the [market price] cost of the energy commodity. The price machine is designed to combine the various cost components to compute the composite electricity price applicable to a particular time/location (or service area)/customer across the state and provide it to the price portal for access by customers and their authorized third-party service providers.

[17] The final working group report is currently scheduled to be filed in CPUC R.22-07-005 on October 12, 2023.

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**e) Internal infrastructure development in support of marginal cost rates adoption**

In support of the development of marginal cost rates, SCE is currently running the CalFUSE Dynamic Rate Pilot which is testing concepts outlined in the CPUC's Demand Flexibility Whitepaper.[18] The results of this pilot, and results from pilots being run by other utilities in the state will inform the development of the marginal cost rates described earlier in this section. On September 25, 2023, SCE filed comments recommending this pilot be extended for an additional year with total fixed costs of $2,520,000 and an annual cost of $9,073,250.[19] Once the CPUC approves an LMS-compliant full-scale RTP rate, additional resources and infrastructure will be needed to add this functionality to SCE's billing system and other existing systems, as well as to build out other new systems such as the price machine, subscription manager, and transactive platform to enable enrollment, calculation, and billing of the rate. These costs have not been estimated by SCE because the systems and functions needed are highly dependent on the eventual rate design.

## 2. Time-dependent rate submission to MIDAS via MIDAS Application Programming Interface (API)

### a. Status of MIDAS submission & plan for ensuring accuracy and maintenance of current time-dependent rates

SCE has been complying with the directives of the LMS by uploading and maintaining prices for time dependent rates, a total of 169 RINs, in MIDAS since July 31, 2023. This includes 63 TOU base rates and their unbundled variants which SCE will update at each rate factor change. Rate factor changes occur approximately 3-6 times per year. This also includes 11 RTP rates which are updated with pricing each evening based on the day's peak temperature. Finally, the uploads include 32 rates with CPP, which is a modifier with time differentiated components.[20]

In December 2023, SCE plans to implement the Solar Billing Plan, which will be the successor to Net Energy Metering 2.0. SCE anticipates that adding this program will result in an additional 236 RINs in 2023 and 118 RINs in 2024 for a total of 523 RINs added in 2024. SCE also plans to scale its manual processes to handle these additional RINs in 2024 until an automated solution is implemented.

SCE is currently implementing an enhancement to SCE's billing system which will compute and upload prices to MIDAS at each rate factor change, as well as automate

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[18] Advanced Strategies for Demand Flexibility Management and Customer DER Compensation, June 22, 2022 available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/ed-white-paper---advanced-strategies-for-demand-flexibility-management.pdf

[19] Opening Comments of Southern California Edison Company on Administrative Law Judge's Ruling on Track B Staff Proposal to Expand Existing Pilots filed in CPUC Rulemaking 22-07-005 on September 25, 2023.

[20] CPP rates are uploaded with "non-event" pricing at each rate factor change. For each CPP event, pricing is updated with event pricing the evening before the day of the event. All rate uploads are currently performed using a combination of semi-automated and manual processes requiring a daily user interface.

and maintain RTP and CPP event pricing in MIDAS daily based on automated receipt of temperature and CPP event information from other systems.  SCE anticipates that this solution will be implemented in March 2024.  From that point on, uploads of prices to MIDAS will be an automated system process triggered by each rate factor update which occur several times per year. Completion of this project is a dependency for another project, which will place the RIN on customer billing statements and our online web portal, which is described in a later section.  SCE estimates the costs for automated upload and maintenance of prices to MIDAS and placement of approximately 523 RINs on customer billing statements and our online web portal to be approximately $1.5M. As time-dependent rates get added into SCE's portfolio, each additional rate will need to be uploaded and maintained in MIDAS.  As explained below, calculation of composite prices for upload into MIDAS requires additional system functionality, and therefore additional cost to implement, test, and maintain. If it is determined, for whatever reason, that a significant number of RINs need to be added beyond the 523, this would be an additional system effort that could have substantial extra costs above the $1.5M mentioned above.

**b. List of current time-dependent rates and their RINs**

Table A-1 and Table A-2 in Appendix A provide a summary of the types of rates SCE is maintaining in MIDAS and a complete list of all permutations of rates currently being maintained in MIDAS with their associated RINs, respectively.

**c. Proof of rates availability on MIDAS (e.g., Large IOUs could attach MIDAS rate download file in JSON format and submit to LMS Implementation Docket 23-LMS-01)**

SCE's rate and hourly price information is currently publicly accessible on MIDAS via the MIDAS API at https://midasapi.energy.ca.gov/.  Any party wanting to examine this information can do so by connecting to the API and downloading the relevant pricing information for SCE's rates.

**d. Calculation of Composite Prices**

Each rate uploaded to MIDAS includes multiple varying components which are summed to create composite prices.  The calculation varies depending on the type of rate, the specific value of the rate, and whether the rate is bundled, where both delivery and generation are provided by SCE, or unbundled, where SCE only provides delivery.

For **volumetric bundled energy prices**, the value is determined by first summing Transmission, Distribution, Nuclear Decommissioning Charge (NDC), California Alternate Rates for Energy (CARE) Surcharge, Public Purpose Programs Charge (PPPC), Reliability Services Balancing Account Adjustment (RSBAA), Transmission Revenue Balancing Account (TRBAA), Transmission Access Charge Balancing Account (TACBA), Public Utilities Commission Reimbursement Fee (PURCF), New System

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Generation Charge (NSGC), and Conservation Incentive Adjustment (CIA) to determine the total delivery charge. Next, Competition Transition Charge (CTC) and Utility Retained Generation (URG) are summed to create the bundled total generation charge. Finally, both total delivery and total generation are summed together to create the total energy charge which is uploaded to MIDAS.

For **volumetric energy prices for rates with CPP**, the non-event price is calculated the same way as the volumetric bundled energy price, plus the "summer CPP non-event energy credit." This credit only applies to residential and small commercial (GS-1) rates. During a CPP event, the price is calculated the same way as the volumetric bundled energy price plus the "CPP event energy charge."

For **volumetric energy prices for existing Schedule RTP rates**, the value is determined by determining the peak temperature for the previous day to determine the correct rate factor tables and then summing Transmission, Distribution, NDC, CARE Surcharge, PPPC, RSBAA, TRBAA, TACBA, PURCF, NSGC, and CIA to determine the total delivery charge. Next, CTC and URG are summed to create the bundled total generation charge. Finally, both total delivery and total generation are summed together to create the total energy charge which is uploaded to MIDAS.

For **volumetric unbundled energy prices**, the value is determined by first summing Transmission, Distribution, NDC, CARE Surcharge, PPPC, RSBAA, TRBAA, TACBA, PURCF, NSGC, and CIA to determine the total delivery charge. The total delivery charge is uploaded to MIDAS absent any generation components because unbundled customers receive their generation from their generation provider and SCE does not have visibility to the generation provider's prices.

For **time-related bundled demand prices**, SCE uploads the sum of the delivery and generation retail demand charges for the specific hours that demand charge applies. The price for the peak demand charge is uploaded for on-peak hours and the price for the mid-peak demand charge is uploaded for mid-peak hours on rates where these charges apply.

For **time-related bundled demand prices for rates with CPP**, the prices for non-event hours are calculated the same way as the time related bundled demand prices, plus the "summer demand credit" and/or the "summer on-peak demand credit". This only applies during summer 4-9pm hours; this does not apply to residential or small commercial (GS-1) rates.

For **time-related unbundled demand prices**, SCE uploads the delivery retail demand charges for the specific hours where the demand charge applies. The price for the delivery peak demand charge is uploaded for on-peak hours and the price for the mid-peak demand charge is uploaded for mid-peak hours on rates where these charges apply. The time related demand charge is uploaded to MIDAS absent any generation components because unbundled customers receive their generation from their generation provider and SCE does not have visibility to the generation provider's prices.

**e. <u>Upload & Maintenance of Additional Rate Components</u>**

The statutory and regulatory provisions that are relevant to this compliance plan are Cal. Public Resources Code § 25403.5 and the LMS regulations (20 CCR §§ 1621-1625). These provisions include the following:

- Any requirements set by the LMS must be "cost-effective when compared with the costs for new electrical capacity." (Public Resources Code § 25403.5).
- The CEC must find the LMS requirements to be "technologically feasible." (Id.)
- The CEC has discretion to "determine that one or more of the load management techniques are infeasible and may delay their adoption[.]" (Id.)
- Any expenses the Large IOUs incur in order to implement the LMS are chargeable to ratepayers and must be treated by the CPUC as allowable in a rate proceeding. (Id.)
- The goal of the LMS is to "establish cost-effective programs and rate structures which will encourage the use of electrical energy at off-peak hours." (20 CCR § 1621).
- The Commission "shall approve" the Large IOUs' submitted plans to comply with Sections 1621 and 1623 if those plans "are consistent with these regulations and . . . show a good faith effort to plan to meet program goals for the standards." (Id.)
- A "time-dependent rate" is "a rate that can vary depending on the time of day to encourage off-peak electricity use and reductions in peak electricity use." (Id.)
- LSEs subject to the LMS regulations must upload to MIDAS their "time-dependent rates" (including "time-dependent cost components") that have been "approved by the rate-approving body." (20 CCR § 1623).

On June 1, 2023, in response to a request for an extension of the deadline for uploads of time-dependent rates to MIDAS by affected load-serving entities (including SCE), the CEC issued an order giving a 1-month extension to upload base rates, and a 3-month extension to upload rates with modifiers after working out the issues noted with CEC staff. In June and July of 2023, the CEC hosted several MIDAS workshops where these topics were discussed, and several of the issues were resolved. During these discussions, the CEC also presented a "CEC Rate Modifier Exclusion Proposal" for determining whether a rate modifier should be uploaded and accepted party comments on the proposal. SCE spent time evaluating the CEC proposal and provided verbal comments in working group meetings and written comments via email.

On September 1, 2023, the CEC filed a document on the docket of proceeding 23-LMS-01 asserting that the "time-dependent rate uploads […] need to include the rate and any price modifiers that affect hourly volumetric (per kWh) electricity prices."[21] In response, SCE, Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) (collectively, the Large IOUs) filed a document in the same docket explaining their position as to what the LMS regulations require to be uploaded to MIDAS, and explaining in particular why the LMS regulations do not require the Large IOUs to upload millions of permutations (in SCE's case, an estimated 17 million) of time-dependent rates combined with non-time-dependent modifiers, which in any event would be neither technologically feasible nor cost-effective, for the reasons discussed herein and in the Large IOUs' response to the CEC's September 1, 2023 document.

After SCE's filing of our LMS Compliance Plan on October 2, 2023, the Large IOUs and CEC staff met multiple times to address how to balance the value of uploading some non-time-dependent rate modifiers to MIDAS with administrative burden and technical challenges. These challenges arise from the millions of potential base rates and modifier combinations that would be required if all non-time-dependent rate modifiers were uploaded. The Large IOUs and CEC staff came to agreement on a set of considerations for each IOU to use when determining what rate modifiers should be uploaded to MIDAS.[22]

SCE then performed a detailed analysis of its non-time-dependent rate modifiers against the considerations which resulted in two groups of modifiers, one group which should be uploaded, and another which should not. Modifiers to be uploaded apply to greater than 0.5 percent of SCE customers, represent a rate impact of greater than $0.01 or 2 percent of the composite $/kWh price, and are technically feasible to upload.

- Modifiers to be uploaded:
  - CARE
  - FERA
  - NEM 2.0
  - SBP Bonus Credit

Modifiers to be excluded from upload are typically small programs that are enrolled in by fewer than 0.5 percent of SCE customers, as well as those modifiers that may be technologically infeasible to upload. For example, Medical Baseline cannot be consistently uploaded because, for most TOU customers enrolled in the program, it provides an additional baseline energy credit that cannot be accurately reflected in prices uploaded to MIDAS.

- Modifiers to be excluded from upload:
  - Commercial CARE

[21] Load Management Standards Implementation Rate Uploads with Price Modifiers posted in 23-LMS-01 on September 1, 2023, p. 2.
[22] On May 24, 2024, CEC staff emailed the Large IOUs the approved template language and reporting tables for IOUs to utilize to apply for exclusions of rate modifiers in its respective LMS compliance plans. A copy of the CEC staff approved template language is included in Appendix C.

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- o Employee Discount
- o Medical Baseline Non-Prime
- o Medical Baseline Prime
- o GTSR-GR
- o GTSR-CR
- o Food Bank Discount
- o DAC CS-GT

Finally, some modifiers were excluded without a detailed analysis because a simple review shows that their inclusion would result in a very large number of RIN permutations which would be infeasible to calculate, upload, and maintain. These modifiers include Power Charge Indifference Adjustment (PCIA) (18 vintages), Utility Users Tax (UUT) (77 UUT factors), and other tax exemptions.

Additional data and analysis on SCE's non-time-differentiated rate modifiers can be found in Appendix D.

Upon approval of this compliance plan and obtaining a cost recovery mechanism for the approximately $1.5 million in funding, SCE will initiate a billing system upgrade to automate the upload of the additional RINs with modifiers. SCE estimates that it will take approximately 9-12 months to complete this project. Upon completion, SCE anticipates that it will be maintaining a total of approximately 1,500 RINs in MIDAS.

**3. Plan to provide Rate Identification Numbers (RINs) on customer billing statements and online accounts using both text and QR code**

In parallel to a billing system enhancement to automate time-dependent dynamic rate submission to MIDAS, SCE is also designing and implementing a billing system enhancement to place RINs on customer billing statements and on the SCE.com “My Account” page where customers can view billing and usage summary information. SCE developed the scope for this project based on the LMS earlier this year and plans to release this upgrade in March 2024, just ahead of the April 2024 compliance deadline. The scope of the project includes placement of the RIN applicable to the customer’s current rate schedule onto customer billing statements in numerical and QR code format as well as a short message telling the customer where they can find more information about the RIN. As discussed in working group meetings, the QR code, when scanned, will return only the RIN itself, for example, “USCA-SCSC-0600-0000,” because the purpose of the QR code is to program apps/devices and not to provide user-readable information. SCE plans to place the RIN between the “Details of your new charges” and “Things you should know” sections of the billing statement because SCE determined that space was both available and near other similar billing details, such as the details of the customer’s rate and their charges.

As part of this billing system enhancement, SCE will also enable generation service providers, such as CCAs, to transmit a RIN and associated message as part of the regular Electronic Data Exchange (EDI) process where generation service providers transmit billing

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details to be printed onto billing statements for their customers.  SCE will use a software tool to convert the text-based RIN into a QR code and then print the QR Code, text-based RIN, and associated message (if provided) onto the billing statement in the area designated for unbundled charges.

## 4. Planned and Current Participation in the Development of a Single Statewide RIN Access Tool

SCE has part-time participation of a Senior Project Manager from SCE's "Pricing Implementation" team to represent SCE in the initial stages of this effort.  As the scope and requirements of the Statewide Tool are defined, SCE will provide additional technical and business resources, if needed, to support the planning, development and implementation activities.  Projects of this type typically require resources from Information Technology, including Cybersecurity for the technical implementation.  Additionally, business resources from Customer Billing, Rate Design, Digital Experience, and other customer service operations teams are needed to provide SCE specific rate composition and inform the end-user experience. It is also possible that third party systems, such as GridX or Green Button, may also be impacted and require modifications to support any changes. And finally, additional costs and resources may be needed to support any marketing, education & outreach.

SCE anticipates that the regulated parties will work together to develop a scope and requirements for the statewide tool and gather some information regarding pricing through a request for information (RFI) or similar process. SCE anticipates that coordinating 18 regulated entities to develop a statewide tool while also receiving input from other stakeholders may prove challenging and recommends that a regulatory body like the CEC take on the role of coordinating parties or hire a third-party facilitator.  After the Compliance Plan is presented to the CEC on October 2, 2023 and then later approved by the CEC, SCE anticipates that it will then request funding through a CPUC-approved mechanism authorized in the CPUC's DFOIR proceeding or another appropriate proceeding.

The primary infrastructure upgrades needed to support the statewide tool may likely require upgrades to our billing or other systems, which would be used to send customer usage information and other customer rate/program identification information to the statewide tool so that rate eligibility and price comparison can be accomplished.  As the scope of the statewide tool is developed, SCE will strive to make sure that our systems are able to be upgraded to provide the needed functionality in a cost-effective manner.  Once the scope is complete, SCE will develop a cost estimate for any billing system upgrades, resource needs, and other required activities. This value would be added to and included in the funding request described above.

SCE has been working with the other regulated load serving entities on creating the statewide RIN tool pursuant to 20 CCR Section 1623(c).  A proposed plan for the tool was submitted to the CEC for review on October 1, 2024. We will continue to work with the other LSEs and the CEC to implement and maintain the statewide RIN tool in a timely manner subject to the tool's approval by the Commission.

## 5. List of alternative cost-effective, LMS-compliant programs and rates

Section 1623(d)(1) states: "*No later than eighteen (18) months after April 1, 2023, each Large IOU shall submit to the Executive Director a list of load flexibility programs deemed cost-effective by the Large IOU. The portfolio of identified programs shall provide any customer with at least one option for automating response to MIDAS signals indicating marginal cost-based rates, marginal prices, hourly or sub hourly marginal greenhouse gas emissions, or other Commission-approved marginal signal(s) that enable automated end-use response.*"

Section 1623(d)(2) states: *"Within forty-five (45) months of April 1, 2023, each Large IOU shall offer to each of its electricity customers voluntary participation in a marginal cost-based rate developed according to Section 1623(a) if such rate is approved by the Large IOU's rate-approving body, or a cost-effective program identified according to Section 1623(d)(1) if such rate is not yet approved by the Large IOU's rate-approving body."*

In the event a marginal cost-based, full-scale RTP rate has not been approved by SCE's rate-approving bodies by January 1, 2027, SCE notes the combination of its current Template Based RTP (TB-RTP) program and its ongoing Expanded SCE Flexible Pricing Rate Pilot represent alternative dynamic pricing rate offerings to meet the compliance requirement as defined in Section 1623(d)(1)-(2). Continuing to offer these two programs to customers during the interim period is the most cost-effective approach to complying with the requirements of Section 1623(d)(1)-(2), as SCE will not be required to develop and implement new rate offerings that will only be available for approximately 10-months before being superseded by the full-scale RTP rates. SCE has already deployed the TB-RTP rate to most rate classes and currently uploads TB-RTP rates to MIDAS on a daily basis. The TB-RTP hourly pricing is updated the evening before the day the pricing is effective. All rate uploads are currently performed using a combination of semi-automated and manual processes requiring a daily user interface. The TB-RTP pricing is based on generation marginal costs, is applied hourly, with a continuous temperature-based pricing signal that adjusts hourly pricing. However, the TB-RTP rate lacks the DLAP pricing, marginal pricing for distribution and transmission, and is currently not offered to residential customers. To make up for these deficiencies, SCE will continue to enroll customers into its Expanded SCE Flexible Pricing Rate Pilot that reflects all the rate design elements required under the LMS and does not reflect the deficiencies in the TB-RTP rate. From this perspective, offering the TB-RTP rate and the Expanded SCE Flexible Pricing Rate Pilot as alternative solutions prior to the implementation of full-scale RTP rates is the most cost-effective approach.

## 6. Plan for conducting public information program

In a September 25, 2023 response to the *Administrative Law Judge's Ruling on Track B Staff Proposal to Expand Existing Pilots* filed in the DFOIR proceeding, SCE requested

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funding to support Marketing, Education, and Outreach (ME&O) for dynamic rates. First, SCE requested funds to create a webpage to provide visibility to SCE's Flexible Pricing Rate Pilot. The webpage would explain the pilot, as well as the benefits of dynamic rates. The webpage would also include a fact sheet,[23] which is already existing and available publicly for use, describing the program and the benefits of dynamic rates. The webpage would also include a list of participating Automation Service Providers (ASPs) that the customer can reach out to, depending on the technology available in their home or business.

In addition, SCE requested funds to support an annual email to targeted customers known to SCE to have qualifying equipment (such as EV, HVAC, or storage). This is in addition to the existing promotion already being conducted by the Automation Service Providers that are participating in the pilot. The email would describe the pilots and the benefits of dynamic rates and would provide a call to action to enroll.

Assuming timely approval of SCE's proposal, SCE intends to launch this additional marketing in 2024, with emails running annually if the program is not fully enrolled.

There may also be ME&O needed to support the Statewide RIN tool. The degree of SCE involvement may weigh heavily on the extent there will be a separate promotion at a statewide level, if at all – this should be discussed as part of the working group meetings regarding the tool's design.

Regarding the promotion of a dynamic rate to meet compliance in 2027 – the design of the rate will heavily influence the nature and extent of the ME&O needed to promote the rate effectively. At this time, it would be premature to provide any cost or resource estimates until further details are established within the CPUC's DFOIR proceeding.

**<u>Conclusion</u>**

SCE appreciates the review and approval of its LMS Compliance Plan and looks forward to working with the CEC and other rate approving authorities on load management and dynamic pricing initiatives. Please do not hesitate to contact me, or Robert Thomas at (626) 302-3505 or Robert.Thomas@sce.com, with any questions or concerns you may have. I am available to discuss these matters further at your convenience.

Very truly yours,

/s/

Robert Thomas

[23] A copy of SCE's Flexible Pricing Rate Pilot Fact Sheet is contained herein in Appendix B.

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# Appendix A

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**Table A-1: Summary of Rates Maintained in MIDAS as of October 1, 2023**

| Rate Type | Base Variant | Unbundled Variant | Total |
|---|---|---|---|
| TOU | 63 | 63 | 126 |
| RTP | 11 | 0 | 11 |
| TOU with CPP | 32 | 0 | 32 |
| | | | **169** |

**Table A-2: List of Rates & RINs**

| Rate Name | AltRateName1 | AltRateName2 | RIN |
|---|---|---|---|
| Time-of-Use Domestic Tiered | TDT | | USCA-SCSC-0100-0000 |
| Time-of-Use Domestic Tiered | TDT | | USCA-SCXX-0100-0000 |
| Time-of-Use Domestic Tiered-CPP | TDT | | USCA-SCSC-0101-0000 |
| Time-Of-Use Domestic Option A | TDA | | USCA-SCSC-0200-0000 |
| Time-Of-Use Domestic Option A | TDA | | USCA-SCXX-0200-0000 |
| Time-Of-Use Domestic Option A-CPP | TDA | | USCA-SCSC-0201-0000 |
| Time-Of-Use Domestic Option B | TDB | | USCA-SCSC-0300-0000 |
| Time-Of-Use Domestic Option B | TDB | | USCA-SCXX-0300-0000 |
| Time-Of-Use Domestic Option B-CPP | TDB | | USCA-SCSC-0301-0000 |
| TOU-D 4-9 PM | TD49 | | USCA-SCSC-0400-0000 |
| TOU-D 4-9 PM | TD49 | | USCA-SCXX-0400-0000 |
| TOU-D 4-9 PM-CPP | TD49 | | USCA-SCSC-0401-0000 |
| TOU-D 5-8 PM | TD58 | | USCA-SCSC-0500-0000 |
| TOU-D 5-8 PM | TD58 | | USCA-SCXX-0500-0000 |
| TOU-D 5-8 PM-CPP | TD58 | | USCA-SCSC-0501-0000 |
| TOU-D-PRIME | TDPRIME | | USCA-SCSC-0600-0000 |
| TOU-D-PRIME | TDPRIME | | USCA-SCXX-0600-0000 |
| TOU-D-PRIME-CPP | TDPRIME | | USCA-SCSC-0601-0000 |
| GS: TOU-GS-1-A (Grandfathered) | TG1A | | USCA-SCSC-0700-0000 |
| GS: TOU-GS-1-A (Grandfathered) | TG1A | | USCA-SCXX-0700-0000 |
| GS: TOU-GS-1-A (Grandfathered)-CPP | TG1A | | USCA-SCSC-0701-0000 |
| TOU-GS-1-E | TG1E | | USCA-SCSC-0800-0000 |
| TOU-GS-1-E | TG1E | | USCA-SCXX-0800-0000 |
| TOU-GS-1-E-CPP | TG1E | | USCA-SCSC-0801-0000 |
| TOU-GS-1-ES | TG1ES | | USCA-SCSC-0900-0000 |
| TOU-GS-1-ES | TG1ES | | USCA-SCXX-0900-0000 |
| TOU-GS-1-ES-CPP | TG1ES | | USCA-SCSC-0901-0000 |
| GS: TOU-GS-1-B (Grandfathered) | TG1B | | USCA-SCSC-1000-0000 |
| GS: TOU-GS-1-B (Grandfathered) | TG1B | | USCA-SCXX-1000-0000 |
| TOU-GS-1-D | TG1D | | USCA-SCSC-1100-0000 |
| TOU-GS-1-D | TG1D | | USCA-SCXX-1100-0000 |

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| Rate Name | AltRateName1 | AltRateName2 | RIN |
|---|---|---|---|
| General Service - TOU-GS-1-LG | TG1LG | | USCA-SCSC-1200-0000 |
| General Service - TOU-GS-1-LG | TG1LG | | USCA-SCXX-1200-0000 |
| General Service - TOU-GS-1-LG-CPP | TG1LG | | USCA-SCSC-1201-0000 |
| TOU-GS-1-D, RTP | TG1DRTP | | USCA-SCSC-1300-0000 |
| General Service - TOU-EV-7-E | TEV7E | | USCA-SCSC-1400-0000 |
| General Service - TOU-EV-7-E | TEV7E | | USCA-SCXX-1400-0000 |
| General Service - TOU-EV-7-D | TEV7D | | USCA-SCSC-1500-0000 |
| General Service - TOU-EV-7-D | TEV7D | | USCA-SCXX-1500-0000 |
| TOU-GS-2-E | TG2E | | USCA-SCSC-1600-0000 |
| TOU-GS-2-E | TG2E | | USCA-SCXX-1600-0000 |
| General Service - TOU-GS-2-B (GF) | TG2B | | USCA-SCSC-1700-0000 |
| General Service - TOU-GS-2-B (GF) | TG2B | | USCA-SCXX-1700-0000 |
| General Service - TOU-GS-2-B (GF)-CPP | TG2B | | USCA-SCSC-1701-0000 |
| TOU-GS-2-D | TG2D | | USCA-SCSC-1800-0000 |
| TOU-GS-2-D | TG2D | | USCA-SCXX-1800-0000 |
| TOU-GS-2-D-CPP | TG2D | | USCA-SCSC-1801-0000 |
| GS: TOU-GS-2-R (Grandfathered) | TG2R | | USCA-SCSC-1900-0000 |
| GS: TOU-GS-2-R (Grandfathered) | TG2R | | USCA-SCXX-1900-0000 |
| TOU-GS-2-D, RTP | TG2DRTP | | USCA-SCSC-2000-0000 |
| TOU-EV-8 | TEV8 | | USCA-SCSC-2100-0000 |
| TOU-EV-8 | TEV8 | | USCA-SCXX-2100-0000 |
| TOU-GS-3-E | TG3E | | USCA-SCSC-2200-0000 |
| TOU-GS-3-E | TG3E | | USCA-SCXX-2200-0000 |
| General Service - TOU-GS-3-B (GF) | TG3B | | USCA-SCSC-2300-0000 |
| General Service - TOU-GS-3-B (GF) | TG3B | | USCA-SCXX-2300-0000 |
| General Service - TOU-GS-3-B (GF)-CPP | TG3B | | USCA-SCSC-2301-0000 |
| TOU-GS-3-D | TG3D | | USCA-SCSC-2400-0000 |
| TOU-GS-3-D | TG3D | | USCA-SCXX-2400-0000 |
| TOU-GS-3-D-CPP | TG3D | | USCA-SCSC-2401-0000 |
| TOU-GS-3-R | TG3R | | USCA-SCSC-2500-0000 |
| TOU-GS-3-R | TG3R | | USCA-SCXX-2500-0000 |
| TOU-GS-3-D, RTP | TG3DRTP | | USCA-SCSC-2600-0000 |
| TOU-EV-9 | TEV9 | SEC | USCA-SCSC-2700-0000 |
| TOU-EV-9 | TEV9 | SEC | USCA-SCXX-2700-0000 |
| TOU-EV-9 | TEV9 | PRI | USCA-SCSC-2800-0000 |
| TOU-EV-9 | TEV9 | PRI | USCA-SCXX-2800-0000 |
| TOU-EV-9 | TEV9 | SUB | USCA-SCSC-2900-0000 |
| TOU-EV-9 | TEV9 | SUB | USCA-SCXX-2900-0000 |
| TOU-8-E | T8E | SEC | USCA-SCSC-3000-0000 |

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| Rate Name | AltRateName1 | AltRateName2 | RIN |
|---|---|---|---|
| TOU-8-E | T8E | SEC | USCA-SCXX-3000-0000 |
| TOU-8-E | T8E | PRI | USCA-SCSC-3100-0000 |
| TOU-8-E | T8E | PRI | USCA-SCXX-3100-0000 |
| TOU-8-E | T8E | SUB | USCA-SCSC-3200-0000 |
| TOU-8-E | T8E | SUB | USCA-SCXX-3200-0000 |
| TOU-8-D | T8D | SEC | USCA-SCSC-3300-0000 |
| TOU-8-D | T8D | SEC | USCA-SCXX-3300-0000 |
| TOU-8-D-CPP | T8D | SEC | USCA-SCSC-3301-0000 |
| TOU-8-D | T8D | PRI | USCA-SCSC-3400-0000 |
| TOU-8-D | T8D | PRI | USCA-SCXX-3400-0000 |
| TOU-8-D-CPP | T8D | PRI | USCA-SCSC-3401-0000 |
| TOU-8-D | T8D | SUB | USCA-SCSC-3500-0000 |
| TOU-8-D | T8D | SUB | USCA-SCXX-3500-0000 |
| TOU-8-D-CPP | T8D | SUB | USCA-SCSC-3501-0000 |
| TOU-8 Option B | T8B | SEC | USCA-SCSC-3600-0000 |
| TOU-8 Option B | T8B | SEC | USCA-SCXX-3600-0000 |
| TOU-8 Option B-CPP | T8B | SEC | USCA-SCSC-3601-0000 |
| TOU-8 Option B | T8B | PRI | USCA-SCSC-3700-0000 |
| TOU-8 Option B | T8B | PRI | USCA-SCXX-3700-0000 |
| TOU-8 Option B-CPP | T8B | PRI | USCA-SCSC-3701-0000 |
| TOU-8 Option B | T8B | SUB | USCA-SCSC-3800-0000 |
| TOU-8 Option B | T8B | SUB | USCA-SCXX-3800-0000 |
| TOU-8 Option B-CPP | T8B | SUB | USCA-SCSC-3801-0000 |
| General Service - TOU-8-R | T8R | SEC | USCA-SCSC-3900-0000 |
| General Service - TOU-8-R | T8R | SEC | USCA-SCXX-3900-0000 |
| General Service - TOU-8-R | T8R | PRI | USCA-SCSC-4000-0000 |
| General Service - TOU-8-R | T8R | PRI | USCA-SCXX-4000-0000 |
| General Service - TOU-8-R | T8R | SUB | USCA-SCSC-4100-0000 |
| General Service - TOU-8-R | T8R | SUB | USCA-SCXX-4100-0000 |
| TOU-8-A, STANDBY | T8AS | SEC | USCA-SCSC-4200-0000 |
| TOU-8-A, STANDBY | T8AS | SEC | USCA-SCXX-4200-0000 |
| TOU-8-A, STANDBY-CPP | T8AS | SEC | USCA-SCSC-4201-0000 |
| TOU-8-A, STANDBY | T8AS | PRI | USCA-SCSC-4300-0000 |
| TOU-8-A, STANDBY | T8AS | PRI | USCA-SCXX-4300-0000 |
| TOU-8-A, STANDBY-CPP | T8AS | PRI | USCA-SCSC-4301-0000 |
| TOU-8-A, STANDBY | T8AS | SUB | USCA-SCSC-4400-0000 |
| TOU-8-A, STANDBY | T8AS | SUB | USCA-SCXX-4400-0000 |
| TOU-8-A, STANDBY-CPP | T8AS | SUB | USCA-SCSC-4401-0000 |
| TOU-8-LG, STANDBY | T8LGS | SEC | USCA-SCSC-4500-0000 |

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| Rate Name | AltRateName1 | AltRateName2 | RIN |
|---|---|---|---|
| TOU-8-LG, STANDBY | T8LGS | SEC | USCA-SCXX-4500-0000 |
| TOU-8-LG, STANDBY-CPP | T7LGS | SEC | USCA-SCSC-4501-0000 |
| TOU-8-LG, STANDBY | T8LGS | PRI | USCA-SCSC-4600-0000 |
| TOU-8-LG, STANDBY | T8LGS | PRI | USCA-SCXX-4600-0000 |
| TOU-8-LG, STANDBY-CPP | T7LGS | PRI | USCA-SCSC-4601-0000 |
| TOU-8-LG, STANDBY | T8LGS | SUB | USCA-SCSC-4700-0000 |
| TOU-8-LG, STANDBY | T8LGS | SUB | USCA-SCXX-4700-0000 |
| TOU-8-LG, STANDBY-CPP | T7LGS | SUB | USCA-SCSC-4701-0000 |
| TOU-8 Option B, STANDBY | T8BS | SEC | USCA-SCSC-4800-0000 |
| TOU-8 Option B, STANDBY | T8BS | SEC | USCA-SCXX-4800-0000 |
| TOU-8 Option B, STANDBY | T8BS | PRI | USCA-SCSC-4900-0000 |
| TOU-8 Option B, STANDBY | T8BS | PRI | USCA-SCXX-4900-0000 |
| TOU-8 Option B, STANDBY | T8BS | SUB | USCA-SCSC-5000-0000 |
| TOU-8 Option B, STANDBY | T8BS | SUB | USCA-SCXX-5000-0000 |
| TOU-8 Option D, STANDBY | T8DS | SEC | USCA-SCSC-5100-0000 |
| TOU-8 Option D, STANDBY | T8DS | SEC | USCA-SCXX-5100-0000 |
| TOU-8 Option D, STANDBY | T8DS | PRI | USCA-SCSC-5200-0000 |
| TOU-8 Option D, STANDBY | T8DS | PRI | USCA-SCXX-5200-0000 |
| TOU-8 Option D, STANDBY | T8DS | SUB | USCA-SCSC-5300-0000 |
| TOU-8 Option D, STANDBY | T8DS | SUB | USCA-SCXX-5300-0000 |
| TOU-8-D-RTP | T8DRTP | SEC | USCA-SCSC-5400-0000 |
| TOU-8-D-RTP | T8DRTP | PRI | USCA-SCSC-5500-0000 |
| TOU-8-D-RTP | T8DRTP | SUB | USCA-SCSC-5600-0000 |
| TOU-8-D-RTP, STANDBY | T8DRTPS | SEC | USCA-SCSC-5700-0000 |
| TOU-8-D-RTP, STANDBY | T8DRTPS | PRI | USCA-SCSC-5800-0000 |
| TOU-8-D-RTP, STANDBY | T8DRTPS | SUB | USCA-SCSC-5900-0000 |
| TOU-PA-2-A (GF) | TP2A | | USCA-SCSC-6000-0000 |
| TOU-PA-2-A (GF) | TP2A | | USCA-SCXX-6000-0000 |
| TOU-PA-2-B (GF) | TP2B | | USCA-SCSC-6100-0000 |
| TOU-PA-2-B (GF) | TP2B | | USCA-SCXX-6100-0000 |
| TOU-PA-2-B (GF)-CPP | TP2B | | USCA-SCSC-6101-0000 |
| TOU-PA-2-E 4pm to 9pm | TP2E49 | | USCA-SCSC-6200-0000 |
| TOU-PA-2-E 4pm to 9pm | TP2E49 | | USCA-SCXX-6200-0000 |
| TOU-PA-2-D 4pm to 9pm | TP2D49 | | USCA-SCSC-6300-0000 |
| TOU-PA-2-D 4pm to 9pm | TP2D49 | | USCA-SCXX-6300-0000 |
| TOU-PA-2-D 4pm to 9pm-CPP | TP2D49 | | USCA-SCSC-6301-0000 |
| TOU-PA-2-E 5pm to 8pm | TP2E58 | | USCA-SCSC-6400-0000 |
| TOU-PA-2-E 5pm to 8pm | TP2E58 | | USCA-SCXX-6400-0000 |
| TOU-PA-2-D 5pm to 8pm | TP2D58 | | USCA-SCSC-6500-0000 |

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| Rate Name | AltRateName1 | AltRateName2 | RIN |
|---|---|---|---|
| TOU-PA-2-D 5pm to 8pm | TP2D58 | | USCA-SCXX-6500-0000 |
| TOU-PA-2-D 5pm to 8pm-CPP | TP2D58 | | USCA-SCSC-6501-0000 |
| TOU-PA-2-D, RTP | TP2DRTP | | USCA-SCSC-6600-0000 |
| TOU-PA-3-A | TP3A | | USCA-SCSC-6700-0000 |
| TOU-PA-3-A | TP3A | | USCA-SCXX-6700-0000 |
| TOU-PA-3-B | TP3B | | USCA-SCSC-6800-0000 |
| TOU-PA-3-B | TP3B | | USCA-SCXX-6800-0000 |
| TOU-PA-3-B-CPP | TP3B | | USCA-SCSC-6801-0000 |
| TOU-PA-3-E 4pm to 9pm | TP3E49 | | USCA-SCSC-6900-0000 |
| TOU-PA-3-E 4pm to 9pm | TP3E49 | | USCA-SCXX-6900-0000 |
| TOU-PA-3-D 4pm to 9pm | TP3D49 | | USCA-SCSC-7000-0000 |
| TOU-PA-3-D 4pm to 9pm | TP3D49 | | USCA-SCXX-7000-0000 |
| TOU-PA-3-D 4pm to 9pm-CPP | TP3D49 | | USCA-SCSC-7001-0000 |
| TOU-PA-3-E 5pm to 8pm | TP3E58 | | USCA-SCSC-7100-0000 |
| TOU-PA-3-E 5pm to 8pm | TP3E58 | | USCA-SCXX-7100-0000 |
| TOU-PA-3-D- 5pm to 8pm | TP3D58 | | USCA-SCSC-7200-0000 |
| TOU-PA-3-D- 5pm to 8pm | TP3D58 | | USCA-SCXX-7200-0000 |
| TOU-PA-3-D- 5pm to 8pm-CPP | TP3D58 | | USCA-SCSC-7201-0000 |
| TOU-PA-3-D, RTP | TP3DRTP | | USCA-SCSC-7300-0000 |
| AL-2 Outdoor Area Lighting (Metered, TOU) | AL2 | | USCA-SCSC-7400-0000 |
| AL-2 Outdoor Area Lighting (Metered, TOU) | AL2 | | USCA-SCXX-7400-0000 |

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# Appendix B

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SOUTHERN CALIFORNIA
EDISON®
Energy for What's Ahead®

## SCE Flexible Pricing Rate Pilot

# AN EXCITING OPPORTUNITY FOR SOUTHERN CALIFORNIA EDISON (SCE) CUSTOMERS

Southern California Edison is currently piloting a special flexible pricing program for customers with select smart electric devices, such as smart thermostats, battery storage devices, or an electric vehicle. The pilot will utilize hourly energy prices that will test the capability of customers' smart devices to automatically shift electricity usage to times of day when energy is less expensive and can be generated with lower emissions. Shifting energy usage to optimal times has the potential to improve the reliability of the electric system while providing savings for customers.

The pilot program is under consideration by the state of California as a potential tool to help accelerate the transition to clean (carbon-free) energy, improve the reliability of the power grid, and reduce the cost of providing electricity.

The pilot program is being facilitated by third-party Automation Service Providers (ASPs) partnering with SCE, in conjunction with a vendor named TeMix Inc., to help customers and their smart devices optimize energy consumption.

### How will I be compensated under this pilot?

You will continue to receive electric service from SCE on your current rate, and you are expected to pay your regular bill as normal. At the same time, you will receive monthly updates from your ASP on any calculated savings you may have achieved by your devices as a result of the flexible pricing rate in the pilot.

At the end of 12 months of participation, the monthly regular bills you paid will be compared against the bills based on the SCE flexible pricing rate under the pilot. If you saved money on the SCE flexible pricing rate, your ASP will provide you with an incentive payment for the difference. If you did not save money on the SCE flexible pricing rate, you will incur no cost. Customers who are on Net Energy Metering plans will receive their compensation (if any) at the end of their relevant period, even if it comes before the 12 months. Customers are free to leave the pilot at any time — if you realized any savings based on flexible pricing, you will be compensated within 12 weeks of your departure from the pilot.

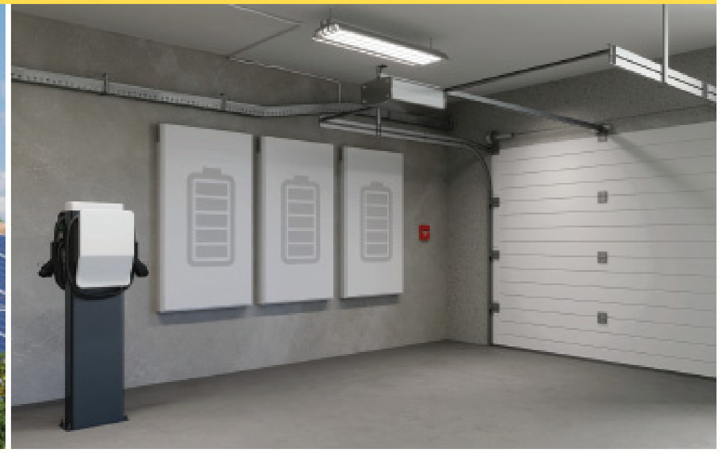
### What devices are eligible?

To participate in this study, you must have an SCE smart utility meter[1] and one or more smart devices. Smart devices include, but are not limited to:

- Devices that control when and how much energy is consumed or produced, such as thermostats, heat pump water heaters, pool pumps, etc.
- Behind-the-meter batteries
- Electric vehicles
- An energy management system

-

## SCE Flexible Pricing Rate Pilot



### Will I be notified of changes in usage of my device(s)?

Depending on your device, your device may be able to display if it is currently being impacted by an event and is either not charging or running or charging or running at a different level. Your ASP may choose to notify you as well. The software or systems that your ASP manages will receive price information and react accordingly. You as a customer may have the ability to override any changes the software might make.

### How do I get started and participate in the pilot?

- You can **enroll** through your ASP, which will work with you to determine your eligibility and start date.
- If you do not already have one, you will likely need to **sign an agreement** with an ASP to allow them to access and manage your smart device's participation in SCE's pilot.
- You will need to give permission to your ASP and other vendors facilitating the pilot, such as TeMix Inc., to **access** your smart meter and billing data held by SCE on your behalf.
- You will need to provide your email address and possibly other **contact information** to your ASP and other vendors so you can receive monthly updates on what you would have saved.
- The current software and systems that control your device(s) may require **upgrades** by the ASP in order to facilitate this study.
- You may be asked to take a **survey** to share your experience with the rate and other aspects of the study.

## HOW DO I ENROLL?

**For more information, please contact:**

[1] Most SCE customers already have a digital smart meter that measures electricity usage in time intervals and communicates remotely.

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# Appendix C

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## Considerations for Uploading Non-Time-Dependent Rate Modifiers to MIDAS

Title 20 California Code of Regulations (CCR) sections 1623(b) and 1623.1(c) require each party subject to the Load Management Standards regulations (20 CCR section 1621, et seq.) to “upload its existing time-dependent rates applicable to its customers to the Commission's Market Informed Demand Automation Server (MIDAS) database”.

This document was developed in an open, collaborative process and provides information to assist regulated parties in uploading non-time dependent rate modifiers to the California Energy Commission’s (CEC) MIDAS database. The CEC is providing this resource to assist, streamline, and clarify the process by which regulated entities can comply with the regulatory upload requirements. Accordingly, the document discusses factors to consider in deciding which non-time dependent rate modifiers to upload to MIDAS in a technologically feasible, cost-effective way that complies with the regulation, and document these activities in the regulated parties’ Load Management Standards (LMS) compliance plans. Another objective of this document is to ensure that electricity customers receive prices from MIDAS that closely reflect the price per kilowatt hour (kWh) that the customer is paying, while ensuring that the amount of data in MIDAS is not excessive, and that the number of rate identification numbers (RINs) uploaded to MIDAS by utilities is feasible and cost-effective.

**Definitions:**

**Modifier / price modifier** – A non-time-dependent volumetric adjustment to hourly electricity prices. In this document, the following modifier definitions are used:

> **Additive modifier** – A modifier that adjusts prices by adding a fixed amount (monetary) that does not change for a given customer on a given day.
>
> **Ratio modifier** – A modifier that adjusts prices by multiplying by a ratio (or percentage) that does not change for a given customer on a given day.
>
> **Fixed charge modifier** – A modifier that only affects the monthly fixed charge. These modifiers are not uploaded to MIDAS and need not be included in these considerations.
>
> **Tier modifier** – A modifier that only affects the allocation of electricity use into tiers. These modifiers are not uploaded to MIDAS and need not be included in these considerations.

**RIN** – Rate Identification Number, as defined in 1621(c)(13).

**MIDAS** – The Market Informed Demand Automation Server, administered by the CEC.

**Notes:**

1. Clarification: Non-time-dependent volumetric price modifiers to be excluded from MIDAS may be based on one or more criteria from the list below, or other relevant information specified in the compliance plan or annual report.
2. Each modifier is taken as a whole.
    a. For example, all customers enrolled in CARE would be summed to determine if the customer / annual load criteria are met.

-

   b. We do not recommend determining the number of customers on CARE for a specific rate, and then implementing the modifier for some rates and not for others.
3. When preparing the annual compliance plan updates, the utility may provide:
   a. The full list of price modifiers (including modifiers such as utility users tax and power charge indifference adjustment) with their modification amounts, number of customers on the modifier, and total load served to customers on that modifier.
   b. A table showing all of the rate modifiers for exclusion, with explanations and data in the format shown in Attachment A.

**Consideration 1 – Feasibility**
The total number of RINs uploaded by a utility should be manageable and technologically feasible for both the regulated entity and MIDAS. Non-time dependent rate modifiers may be excluded from being uploaded to MIDAS based on infeasibility and the other considerations discussed here.

**Consideration 2 – User Communication**
CEC and regulated parties should communicate to MIDAS users at the time of sign-up, and on MIDAS informational webpages, that MIDAS electricity price data are closely representative, but not precisely accurate depictions of their actual electricity rates. MIDAS electricity prices are designed to inform device operation decisions for the purposes of load flexibility, not to provide precisely accurate total energy cost calculations.

**Consideration 3 – Modifier Exclusion**
Non-time-dependent modifiers may be excluded from MIDAS uploads if:

a. The additional RIN(s) that would be created by including the modifier represents less than 0.5% of the total number of customers served by the utility AND less than 0.5% of total annual load as sales; or
b. The change in price due to the modifier is less than 0.01 $/kWh for additive modifiers OR 2% for ratio modifiers.

**Consideration 4 – RIN Assignment**
The LMS regulations require that customers who are enrolled in any time-dependent rate be assigned a RIN. The RIN should reflect:

a. The base rate that the customer is enrolled in, and
b. The price modifiers that the customer is enrolled in if those modifiers are included in MIDAS.

**Consideration 5 – Modifier Review**
Excluded modifiers should not cause problems with device operation, or for certain groups of customers (e.g., medical baseline, large industrial, etc.), especially where exclusion of the modifier may eliminate the group’s participation in MIDAS. Modifiers should be reviewed for inclusion in MIDAS every year as part of the annual compliance update, or when major issues are reported by third parties, customers, or CEC staff.

**Please complete the attached spreadsheet with all rates, all modifiers, and modifiers considered for exclusion, and include it with your compliance plans and update annually as part of annual reports.**

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# Appendix D

## *(Refer to the Workbook Attachment)*