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October 2, 2023

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 Plans 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) amendments, Southern California Edison (SCE) is hereby submitting its LMS compliance plan (Compliance Plan) for review and approval, as required by Title 20, California Code of Regulations (CCR) Section 1621(d),[1] 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[2] and then apply to its 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 each customer class by January 2025, and offer to customers by January 2027. This marginal cost-based rate must include a marginal cost-based hourly or sub-hourly generation energy and capacity (import only, i.e., delivered to the customer) component, as well as marginal cost-based hourly or sub-hourly distribution and transmission 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.

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[1] 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).

[2] 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

SCE's Compliance Plan for complying with the requirements of Sections 1621 and 1623 is organized as follows:[3]

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 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 will include 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 modification to this plan will be filed as the proceeding timelines at the CPUC and FERC unfold.

1. Marginal rate design and application

SCE currently offers marginal cost-based rate designs, including generation and distribution rate components, to all customer classes. Designing rates based on marginal costs that include the time-dependent relationships associated with a utility's cost of service has been a long-standing policy of the CPUC and practiced by SCE. Transmission rates, however, reflect embedded costs rate design consistent with 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 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 circuit 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

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[3] 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.

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 capacity resource constraints that occur when supply from renewable resource, primarily solar, decreases as the sun sets in addition to capacity constraints associated with 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 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 and produce a final report in the first quarter of 2025. The current schedule for the pilot *may* be extended up to an additional three years through the end of 2027 as recently proposed by the CPUC's Energy Division (ED) Staff. Staff recommended that an extension is necessary, among other things, to "enhance summer reliability, increase customer understanding of operational needs and benefits of load management under dynamic rates, enable utilities and CCAs to gain important operational experience in offering dynamic rates to customers across different applications and capabilities, which should help advance their technical and operational readiness and deployment timelines to offer widespread hourly, marginal-cost-based dynamic rates consistent with CEC's Load Management Standards."[4] SCE's LMS-compliant RTP rate will use CAISO DLAP day-ahead pricing in lieu of production modeling results.

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[4] *See* Attachment: Staff Proposal on Existing Dynamic Rate Pilot Expansion in Demand Flexibility Rulemaking (R.22-07-005), issued on August 15, 2023.

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). To bridge this methodological difference, SCE will perform a transmission marginal cost study, to be filed with the CPUC, to 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 retail rate 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 retail rate parameters established, SCE will file an application with the FERC for retail RTP rates reflecting the established rate parameters, while maintaining the current 12-CP allocation. This approach allows for the most expedient implementation. 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.

a) **Rate design and application timeline**

The Joint IOU Working Group 1 Report (The Working Group Report), to be filed as part of the CPUC's DFOIR, discusses the timing of pilots and other procedural requirements.[5] As discussed in the report, SCE has already made 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 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.[6] 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

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[5] 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.

[6] 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.

classes by January 1, 2027. Initial CPUC guidance regarding RTP rate design in the DFOIR, which includes the Flexible Pricing Rate Pilot, is expected by March of 2024. Given the recent CPUC staff proposal for the extensions of the RTP pilots, final guidance may not be received until the second quarter of 2028. Once final guidance regarding RTP rate design has been received, SCE can complete the process of designing rates and preparing a formal application. This step can take approximately 8- to 12-months.

Given that electricity services that deliver hourly prices directly to customer devices represent an entirely new type of service, without precedent in terms of complexity and customer understanding, SCE believes the knowledge gained from the pilots must be used to inform the eventual rate design proposal. Without the knowledge gained from the pilots, the availability of full-scale RTP may require multiple iterations of a full-scale implementation that will come at a greater cost to ratepayers. To avoid this outcome, SCE will require an exemption to the LMS timeline, where full-scale RTP rates will be made available to customers in 2032 or 2033, should the Flexible Pricing Rate Pilot be extended. Although elements of the full-scale RTP rates could be phased in prior to these dates by means of the Stepping-Stones approach as presented in the Working Group Report, the shaded dashed area in *Figure 1* illustrates the additional time associated with the pilot extension, production of the evaluation report, and the time for the CPUC to issue its final guidance. The gap between the date SCE receives final guidance and the estimated availability dates for full-scale RTP rates in 2032 or 2033 represents the time needed to design and implement the rates.

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. The transmission rate design process will also involve an application at the CPUC to litigate transmission marginal costs and the marginal cost 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 FERC, it is likely the submission of a marginal cost proposal directly to the FERC would take significantly 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 at the CPUC a transmission marginal costs study and rate design proposal 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 of costs, 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 with 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 that also affected the design of transmission retail rates.[7] The FERC requires that these Single-Issue applications be filed no sooner than 6-months prior to the implementation date. The timeline in *Figure 1* reflects this requirement.

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[7] *See* FERC Docket ER19-374 to establish three new, commercial EV rate schedules for six CPUC rate groups.

Figure 1: CEC LMS / SCE Flexible Rate Pilot / CPUC / FERC Regulatory Timeline
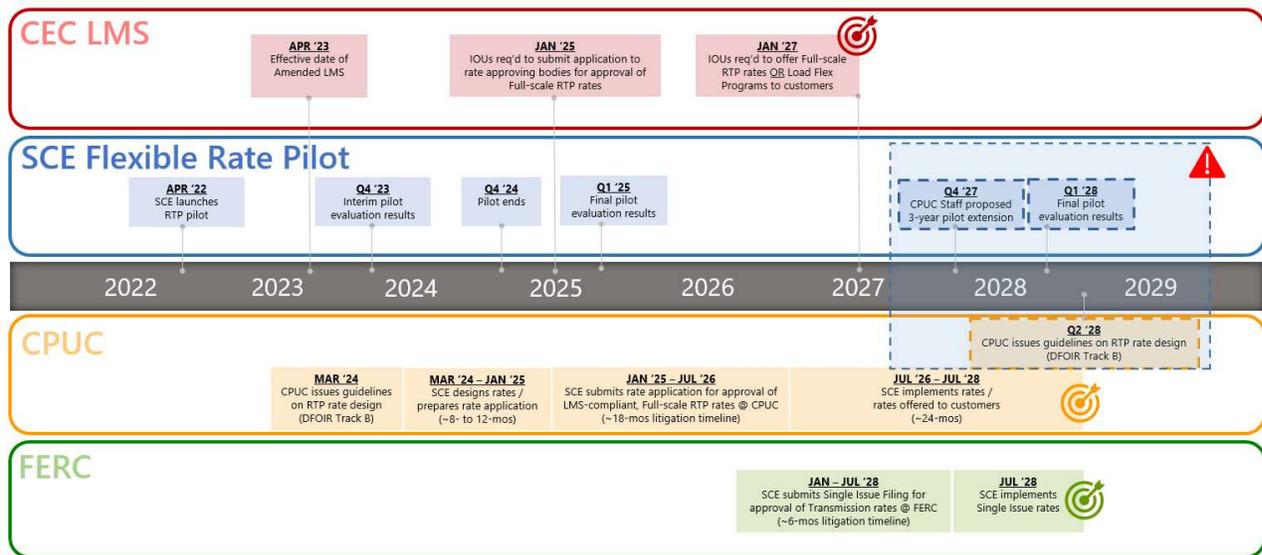
With approval of CPUC Staff's proposal for a 3-year pilot extension, implementation of marginal cost-based dynamic rates as intended in the CEC's LMS will most likely be timed for some time in 2032-33.

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

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. SCE expects to update its Compliance Plan regarding resource commitments after the CPUC issues final guidance on RTP rate designs.

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 Pilot.

Table 1: Current PD&R Resource Commitment and Activity by Year[8]

PD&R Team	2023 MIDAS Implementation, Demand Flex OIR & Flexible Pricing Rate Pilot	2024 MIDAS Implementation, Demand Flex OIR, Flexible Pricing Rate Pilot & CPUC RTP Application	2025 MIDAS Implementation, Demand Flex OIR, Flexible Pricing Rate Pilot & CPUC RTP Application	2026 MIDAS Implementation, Demand Flex OIR, 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

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[8] 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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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.

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

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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.[9] 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.

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-

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[9] 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.

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.[10]

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.[11] 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 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

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[10] 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.

[11] 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.

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transmission pricing are complete, it is premature to assess 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,[12] 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 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

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[12] 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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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 Service Voltage less than 2 kV
TOU-8-PRI	Large Commercial and Industrial - Primary - Metered Load above 500 kW Service Voltage between 2 kV and 50 kV
TOU-8-SUB	Large Commercial and Industrial - Sub-transmission - Metered Load above 500 kW Service Voltage above 50 kV
TOU-8-Standby-SEC	Large Commercial and Industrial - Secondary - Standby - Metered Load above 500 kW Service Voltage less than 2 kV
TOU-8-Standby-PRI	Large Commercial and Industrial - Primary - Standby - Metered Load above 500 kW Service Voltage between 2 kV and 50 kV
TOU-8-Standby-SUB	Large Commercial and Industrial - Sub-transmission - Standby - Metered Load above 500 kW Service Voltage above 50 kV
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

Customer Class	Description
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.[13] 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.[14] 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.

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

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[13] 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.

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

Flexibility Whitepaper.[15] 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.[16] 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.[17]

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 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

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[15] 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

[16] 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.

[17] 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.

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 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. **Upload & Maintenance of Additional Rate Components**

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."[18] 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

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[18] Load Management Standards Implementation Rate Uploads with Price Modifiers posted in 23-LMS-01 on September 1, 2023, p. 2.

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.

SCE has been complying and will continue to comply with the LMS by uploading the time-dependent rate factors of time-dependent rates and time dependent-rate factors of any programs or modifiers to those rates, such as CPP. By doing so, SCE is in compliance with the LMS. In the spirit of mutual collaboration, SCE supports additional discussions with the CEC to determine if there are additional rate components that provide meaningful price differences that impact customer decision-making, and which are technologically feasible and cost-effective to upload and maintain 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 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.

5. List of 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 RTP rate has not been approved by SCE's rate-approving bodies by January 1, 2027, SCE notes its CPP program currently meets the

compliance requirement as defined in Section 1623(d)(1)-(2). SCE has already deployed CPP to most rate groups with time-dependent rates and currently uploads CPP rates to MIDAS with "non-event" pricing at the time of each rate factor change. For each CPP event, the CPP 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. The CPP rate can also be coupled with auto-response equipment to manage load automatically in response to price signals. From this perspective, CPP is a cost-effective dynamic pricing program that can leverage the MIDAS platform.

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 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,[19] 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.

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

<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/

Dawn Anaiscourt

Appendix A

Table of Contents

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
General Service - TOU-GS-1-LG	TG1LG		USCA-SCSC-1200-0000

Rate Name	AltRateName1	AltRateName2	RIN
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
TOU-8-E	T8E	SEC	USCA-SCXX-3000-0000
TOU-8-E	T8E	PRI	USCA-SCSC-3100-0000

Rate Name	AltRateName1	AltRateName2	RIN
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
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

Rate Name	AltRateName1	AltRateName2	RIN
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
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

Rate Name	AltRateName1	AltRateName2	RIN
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

Appendix B

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

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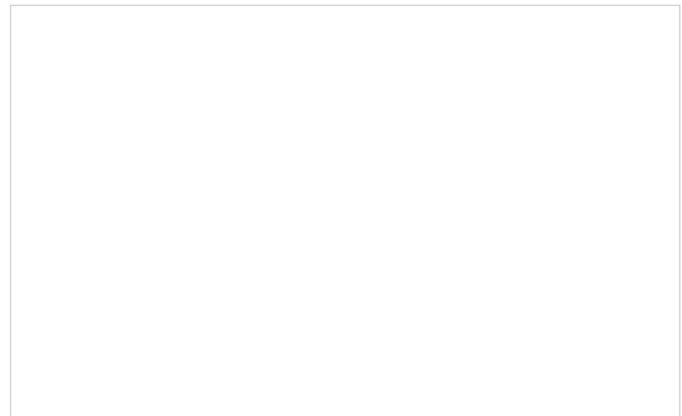
[1]Most SCE customers already have a digital smart meter that measures electricity usage in time intervals and communicates remotely.