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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Update and Reform Energy Resource Recovery Account and Power Charge Indifference Adjustment Policies and Processes.	FILED PUBLIC UTILITIES COMMISSION FEBRUARY 20, 2025 SACRAMENTO, CALIFORNIA RULEMAKING 25-02-005

ORDER INSTITUTING RULEMAKING TO UPDATE AND REFORM ENERGY RESOURCE RECOVERY ACCOUNT AND POWER CHARGE INDIFFERENCE ADJUSTMENT POLICIES AND PROCESSES

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Summary

This order institutes a Rulemaking to consider changes to rules and processes applicable to the electric fuel and purchased power (Energy Resource Recovery Account, or ERRA) annual forecast and compliance proceedings, as well as changes to the Power Charge Indifference Adjustment (PCIA). Some policy or rule changes applicable to broader procurement guidance that impact ERRA may be considered.

This proceeding will consider ERRA and PCIA rules and processes, and whether changes or new rules and processes are warranted. The possibility of adopting various new policies and changes to existing rules has been raised in the large investor-owned electric utilities' annual ERRA forecast and compliance cases in recent years, as well as in other venues such as the utilities' general rate cases. The mechanics and impacts of the PCIA simultaneously play out annually across three ERRA Forecast applications filed by Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company, making joint consideration of PCIA and ERRA changes more efficient. Issues related to the fair treatment of the customers that take bundled service with the electric investor-owned utilities and those who have departed to receive power from other entities such as Community Choice Aggregators and Direct Access providers are also extensively raised in ERRA. These annual forecast ratemaking proceedings have a significant impact on all electric ratepayers, both

in terms of absolute costs for power as well as the fair and equitable division of costs between bundled and departed load customers.

The objectives of this proceeding are to consider and identify reasonable improvements to existing ERRA and PCIA rules, mechanisms, and processes to ensure best practices in utility forecasting and other procurement plan activities; to identify ways to mitigate and respond to rate volatility, whether resulting from market conditions or ratemaking constructs; to best ensure indifference among bundled and departed customers; and to provide policy guidance to ensure that individual utility forecast ratemaking proceedings function as efficiently and consistently as possible.

1. Overview of Energy Resource Recovery Account (ERRA)

The California Public Utilities Commission (Commission) established the Energy Resource Recovery Account (ERRA) regulatory process in Decision (D.) 02-10-062. D.02-10-062 established the ERRA to provide recovery of energy procurement costs, including expenses associated with fuel and purchased power, utility retained generation, California Independent System Operator (CAISO) related costs, and costs associated with the residual net short procurement requirements to bundled electric service customers of the three large electric investor-owned utilities (IOUs). ERRA proceedings include costs for Resource Adequacy (RA) contracts that the utility must buy to meet its reliability requirements, as well as its costs for renewables contracts required under the Renewables Portfolio Standard (RPS). ERRA proceedings also review the utility’s other smaller annual procurement-related costs such as those related to transacting with California's grid operator and complying with California's Greenhouse Gas (GHG) Cap-and-Trade program.

ERRA costs can be volatile and make up a significant part of electricity bills because they are driven by market costs for natural gas, renewables and other retail sources of electricity, RA costs, and by electricity demand and factors like weather. The dollar figures at stake in ERRA forecast proceedings are significant. Recent annual forecast revenue requirements for Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) costs have been in the billions of dollars. For example, the amounts approved in the 2025 ERRA Forecast proceedings were $2.25 billion, $4.637 billion and $71.7 million for PG&E, SCE, and SDG&E, respectively.[1] The amounts approved in the 2024 ERRA forecast proceedings were $2.71 billion, $5.23 billion, and $709.8 million for PG&E, SCE, and SDG&E, respectively.[2] Generation costs, which are a strong proxy for ERRA costs, on average account for 33 percent (%) of a typical residential bundled customer's bill.

All ERRA costs are pass-through costs, meaning that the utility recovers from customers the exact expenditure for the commodities and related costs without applying a rate of return, otherwise known as profit. In addition to being driven by market costs, each utility's procurement obligations also impact ERRA. These obligations include RA and RPS as previously mentioned, but also the

1 D.24-12-038 (PG&E); D.24-12-039 (SCE); and D.24-12-040 (SDG&E).

2 D.23-12-022 (PG&E); D.23-11-094 (SCE); and D.23-12-021 (SDG&E)

costs resulting from special directives such as BioRAM (the smaller forest biomass procurement orders which originally resulted from a tree mortality emergency order).[3]

ERRA costs are distinctly different from capital investments (for which the electric IOUs earn a rate of return) and operations and maintenance costs, all of which are considered in each IOU's respective general rate case (GRC) proceeding. ERRA and GRC costs can be compared to the overall costs of owning a car: the GRC costs address purchase and maintenance costs for the vehicle while ERRA addresses the cost to fuel the vehicle.

ERRA can refer to either the overall proceeding or the ERRA Balancing Account (ERRA BA), which tracks ERRA costs for each electric IOU. ERRA proceedings review costs within the ERRA BA (for the majority of costs related to fuel and purchased power), but also review costs within other balancing and memorandum accounts for various other procurement-related activities.

There are two types of ERRA applications that are filed on a set timeline every year, forward-looking ERRA Forecast applications and backward-looking ERRA Compliance applications. Each are addressed in detail below.

1.1. ERRA Forecast Proceedings and Related True-Up and Trigger Processes

ERRA Forecast applications are filed each May by PG&E, SCE, and SDG&E. These ERRA Forecast applications seek Commission approval of the utility's anticipated procurement costs based on its forecasted electricity demand

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[3] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-procurement-programs/rps-bioram. *See also* Commission Resolution E-4770.

(*i.e.*, sales forecast) for the following year. The ERRA forecast proceedings are resolved on expedited timelines to reach a Commission decision before the end of the year so that resulting rates can be implemented by January 1st of the forecast year (the following calendar year).

ERRA Forecast Proceedings ultimately result in a Commission decision approving three crucial primary elements: a revenue requirement, a sales forecast, and generation rates. The approved ERRA revenue requirement is the total dollar amount each electric IOU is authorized to collect from customers to cover its fuel and purchased power costs in the forecast year. ERRA Forecast Proceedings also consider and adopt a sales forecast, which is the amount of electricity the utility expects its customers to use. Each ERRA Forecast Proceeding also approves generation rates that the utility may charge its customers in the forecast year with the numbers for a revenue requirement and a sales forecast making up the numerator and denominator of the calculation.

ERRA Forecast Proceedings also consider other program costs driven by procurement. The market for GHG allowances under the California Cap-and-Trade program affects forecasted costs, as the utility must buy allowances to account for the emissions associated with its customers' usage. The revenues from the program also impact the California Climate Credit, a twice-annual credit for electric and natural gas customers. Climate Credit amounts for the following year are determined in each ERRA Forecast Proceeding.

ERRA Forecast Proceedings also establish program budgets and costs for several critical customer renewable energy programs. Those programs include the Disadvantaged Communities Green Tariff (DAC-GT) and Solar on Multifamily Affordable Housing (SOMAH) programs.

One important milestone in each annual ERRA forecast proceeding is the October Update, in which the utility updates its application filed in May with more recent figures and estimates for the forecast year. This update provides a more accurate picture of the year ahead.

1.1.1. ERRA Forecast Proceedings True-Up Mechanisms

The ERRA Forecast process runs on a year-ahead cycle and, as with most forecasts, the actual numbers usually do not exactly align with those forecasted. Demand and resource costs are irregular. Unpredictable events like heat waves and cold spells can drive extreme and unforeseen changes in energy costs and demand. Global events like the COVID-19 pandemic and Russia's invasion of Ukraine can cause significant changes in energy use and energy costs. For these reasons, ERRA forecasts are updated (or "trued up") to reflect actual costs to ensure fairness to customers and the utilities. This update is submitted in October to provide a more accurate picture of the year ahead.

The difference between forecast and actual costs, and between forecast and actual sales, affects whether the utility collects more or less than its approved revenue requirement. The extent to which this occurs can be seen in the utility's balancing accounts, either as an undercollection (a negative balance due to the utility not collecting as much forecasted) or an overcollection, where the utility has collected more than forecasted. Higher-than-forecasted costs can lead to an undercollection, because the utility is paying more to provide electricity than it forecast it would. Unexpectedly high electricity demand can lead to an overcollection. These two factors can feed each other, such as when a long summer heat wave leads to both high customer electricity demand and high market prices. If the difference remains small, the correction of deviations from the forecast is trued up in the following ERRA Forecast Proceeding. Every year, the overcollections or undercollections are included either as a debit or a credit in the next year's revenue requirement for each account. This allows small rolling differences to be trued-up, with customers paying only the utility's actual cost.

1.1.2. ERRA Trigger Mechanism

Small deviations from the forecast are trued up in the regular ERRA forecast cycle. Large deviations, however, are addressed mid-cycle in trigger Applications. If the electric IOU is collecting far more revenue than it needs to procure the resources to serve customers – especially if this occurs early in the year – this can pose an unreasonable burden for customers that should be relieved by a downward adjustment in rates. Similarly, if the utility faces real-time market costs that far exceed what it is collecting from consumers, it can face serious revenue challenges necessitating upward rate adjustments. The Commission established an ERRA Trigger Mechanism to deal with overcollections or undercollections that become too large to wait until the following year to be corrected. The ERRA Trigger Mechanism defines 4% as the point between a normal deviation from the forecast that can be resolved the following year in the next forecast Application and deviations that should be addressed immediately. The ERRA Trigger Mechanism allows for mid-year adjustments to ERRA rates in these circumstances, provided that the utility does not reasonably expect the imbalance to correct itself.

Every February the utilities file a Trigger Advice Letter (AL) establishing that year's Trigger Point and Trigger Threshold at ±4% and ±5% respectively of actual recorded generation revenues from the prior calendar year. If the ERRA balance reaches the ±4% trigger point at any time and is forecast to exceed the ±5% threshold, the IOU is required to either: (1) file an advice letter notification that the trigger point has been exceeded, but no rate change is necessary since the utility expects the balance to self-correct within 120 days; or (2) file an expedited application if the utility expects the exceedance will not self-correct within 120 days. In some situations, especially if the trigger point is reached later in the year, the balance is dealt with in the ongoing ERRA forecast and applied to rates in the following year, because there may not be time to change rates before the end of the year. However, if an imbalance is reached earlier in the year, a mid-year rate change resulting from a trigger application proceeding is possible.

While the trigger process provides timelier true ups, it can also contribute to rate volatility and greater complexity around rates. In some situations, the increase or reduction in rates that occurs when an overcollection or undercollection is trued up can obfuscate the costs of energy procurement for consumers.

1.2. ERRA Compliance Proceedings

Each utility also files an ERRA Compliance Application every year for final approval of cost recovery and review of its procurement management activities in the prior year. An ERRA Compliance Proceeding examines whether a utility has complied with all applicable rules, regulations, decisions, and laws in implementing the most recently approved and applicable long-term procurement plan, including prudently administering contracts, ensuring least-cost dispatch, and managing other procurement activities.[4] In the ERRA Compliance Proceeding, the Commission often makes findings with regard to whether, during the record period, the subject electric IOU complied with its Commission-approved Bundled Procurement Plan (BPP) in the areas of fuel procurement, administration of power purchase contracts, GHG compliance instrument procurement, resource adequacy sales, and least-cost dispatch of electric generation resources. If the Commission finds that there was a deviation from the responsibilities and obligations of the electric IOU to manage its contracts and operations prudently, there may be a disallowance of revenue to be collected from customers that resulted from the imprudent actions.

One important nuance about the interconnectedness between ERRA forecast and ERRA compliance is that while each ERRA forecast trues up the costs from the prior year, final cost recovery authorization of those costs is approved in the ERRA compliance case for that year.

1.3. Broader Issues Arising in ERRA

As part of reviewing renewable market prices, RA capacity prices, and other costs from procurement, ERRA proceedings naturally implement procurement rules that were considered and adopted in other proceedings. As such, the ERRA process itself is intended to function as an individual electric IOU's annual forecast and accounting review, not as a forum for evaluating or setting policy.

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[4] Public Utilities (Pub. Util.) Code § 454.5(d)(2).

A certain amount of policy decision-making is inherent within a thorough consideration of customer programs and procurement obligations, even in streamlined proceedings focused on ratemaking. But a range of policy issues arising in recent ERRA proceedings and other ratemaking cases have demonstrably strained the limits of individual cases. A substantial subset of these questions relates to our mechanism for ensuring customer indifference to retail load departure, the Power Charge Indifference Adjustment (PCIA).

1.3.1. The Power Charge Indifference Adjustment

Issues related to retail choice among load-serving entities are one of the major areas of consideration in the ERRA process. Retail choice refers to customers' options to receive the electricity commodity service from an entity other than their incumbent electric IOU. All customers, regardless of their choice of provider for the electric commodity service, still use the physical electric grid owned and operated by the utility. Customers whose load departs the incumbent utility for a third-party provider receive the electric commodity service from the non-utility entity, but the incumbent electric IOU continues to provide the electric delivery and billing services to the customer.

Since the adoption of Assembly Bill (AB) 117 (2003), Californians have seen an expansion in the number of Community Choice Aggregators (CCAs) which have formed as local governments to engage directly in serving the electricity demand of their jurisdictions. In addition to local governments that form CCAs to serve local load, some customers, typically large commercial and industrial customers, also receive their energy supply from electric service providers (ESP) that provide direct access (DA) service. DA service is a private sector analogue to the customer choice options provided by CCAs.

When a CCA is formed, or a customer receives DA service from an ESP, the ESP or CCA takes over the responsibility to procure electricity to meet the demand of its customers. The utility has planned for those customers' future load, procuring long-term energy, capacity, and renewables contracts to meet its long-range procurement obligations. When customers depart the utility to take service from a third party, the customer has an obligation to cover any residual procurement costs incurred by the incumbent utility on the customers' behalf. Thus, in accordance with the Pub. Util. Code and existing policy, processes and mechanisms for ensuring fairness and indifference to all customers are necessary. These processes are complex, often contentious, and often at issue in the utilities' annual ERRA forecast proceedings.

The PCIA, a ratemaking element that enacts and ensures indifference to all customers, bundled and unbundled, is the mechanism developed to facilitate cost equity between third-party providers and the incumbent utility. The PCIA revenue requirement and rates are calculated annually as part of each IOU's ERRA Forecast proceeding. The PCIA implements Pub. Util. Code Sections 366.1 and 366.2, 365.28 and 366.39, which require that (1) bundled service IOU customers do not experience any cost increases due to the departure of retail customers, and (2) customers who depart IOU service do not experience any cost increases due to an allocation of costs that were not incurred on their behalf. The PCIA was first adopted in D.06-07-030 to replace the Cost Responsibility

Surcharge. The PCIA revenue requirement and rates are calculated annually as part of each IOU's ERRA Forecast proceeding.

D.18-10-019 revised the PCIA to establish the market value of the portfolio by setting Market Price Benchmarks (MPB) based on the weighted average price of market transactions for the following market components: energy index price, RA system, local and flexible capacity, and RPS value. The portfolio market value is calculated using the MPBs for energy, based on Platts forward prices, and the MPBs for RA and RPS, which are determined by the Commission's Energy Division. D.18-10-019 also implemented an annual true-up process to reconcile differences between forecasted and actual values and ensure that bundled and departing load customers pay equally for the residual procurement costs of PCIA-eligible resources, which were collected in the Portfolio Allocation Balancing Account.

There are three components to RA included in the MPB: System RA, Local RA, and Flexible RA. Resources that qualify for Local RA or Flexible RA also qualify for System RA. The differing requirements for System, Local, and Flexible RA produce differing prices for each specific type of contract in the RA Market.

1.3.2. ERRA and PCIA Issues

While the rules and principles established in Rulemaking (R.) 17-06-026 continue to form the overarching framework for ensuring indifference, two concerns have emerged that show a need for adjustment to the current rules: 1) changes in regulatory frameworks that underpin the main elements of the PCIA, in concert with changes to overall market and resource conditions; and 2) the consistent occurrence of issues in individual ratemaking cases that are better addressed in a rulemaking. The first factor reinforces the second, as procurement impacts arising from a broader landscape heighten the stakes for individual IOU applications. There are other issues which have arisen from the implementation of existing rules.

Shifts in today's energy market costs relative to the contract prices of older resources can drive changes in the PCIA and in the relative cost share between bundled and departed customers. In the last 10 years, older renewables contracts, like those executed in the early 2000s, reflected higher prices than current market prices for renewables, as the immense growth in California's renewables market since the creation of the RPS program has helped drive broad decreases in the cost of wind and solar. In some circumstances, electric IOUs still hold the historically higher-cost contracts. In recent years, electric IOUs' legacy portfolios of RPS contracts have been more expensive than the resource portfolios comprised of more recently procured contracts of the CCAs, many of which formed after electric IOU procurement had driven down costs across energy markets. While CCA customers still paid their share of the legacy costs of these higher priced contracts through the PCIA, the IOU still held the more costly share. This general trend has not held true in recent years. The RA market has experienced extreme increases in the price for system RA, specifically during peak summer months. This has led to rapid increases in the RA market price benchmarks in the past few years, which has increased the market value of IOU portfolios compared to the costs of those portfolios, resulting in PCIA shifting from serving as a charge to a credit on the bill of some departed load customers. A PCIA credit does not necessarily suggest a cost shift between bundled and unbundled customers. It can accurately reflect a rebalancing of the costs and market value of the resources the IOUs retain in the portfolio for use by bundled customers. However, it only leads to customer indifference if the MPB accurately reflects the market value of the entire IOU portfolio.

1.4. Purpose of ERRA/PCIA Proceeding

Changes in the relative share of costs do not in themselves indicate a problem. Shifts in markets are inevitable, thus shifts in the PCIA and the relative share of those costs are unavoidable. The issues to be addressed in this rulemaking result from more fundamental market changes, and from repeated or consistently arising problems or opportunities. The RA program has undergone several fundamental changes that are affecting the RA MPB. Issues surrounding rules for vintaging resources (which is key to determining who pays for that resource) have repeatedly arisen in recent utility GRCs, and accounting questions of a policy nature continue to arise in individual ERRA compliance cases. The procurement behavior of utilities and how they manage those resources, especially in light of rules and directions related to reliability, have also become prominent in ERRA compliance.

Forecasting practices for energy procurement have taken on new importance and would benefit from consistency across the utilities. The Commission has already recognized a potential need for addressing these issues in a rulemaking.[5] In light of ongoing cost increases, it is critical for the Commission to address rate volatility wherever possible, including through

[5] D.24-12-039 (SCE ERRA Forecast for 2025).

improvements to our ERRA process timing rules, the implementation of rate changes by the utilities, and improvements to ERRA trigger rules.

The objectives of this proceeding are to:

1) Consider and identify reasonable improvements to existing ERRA and PCIA rules, mechanisms, and processes to ensure best practices in utility forecasting and other procurement plan activities;
2) Identify ways to mitigate and respond to rate volatility, whether resulting from market conditions or ratemaking constructs;
3) Best ensure indifference among bundled and departed customers; and
4) Provide policy guidance to ensure that individual utility forecast ratemaking proceedings function as efficiently and consistently as possible.

2. Jurisdiction

Pub. Util. Code Section 454.5(d)(3) requires that a procurement plan approved by the Commission shall ensure timely recovery of prospective procurement costs and that the Commission shall establish balancing accounts to track differences between recorded revenues and costs incurred pursuant to an approved procurement plan. In D.02-10-062, the Commission established the ERRA balancing account by which PG&E, SCE, and SDG&E track fuel and purchased power revenues against recorded costs.

Pub. Util. Code Section 366.1 requires the Commission to ensure that customers leaving the IOU do not burden remaining customers with costs which were incurred to serve them, such as costs associated with long-term generation procurement. CCA and DA customers are required to pay the non-bypassable

PCIA to ensure this "customer indifference." The PCIA is also charged to bundled service customers, since both bundled customers and those who have left IOU service to purchase electricity from other providers must pay for the residual procurement costs for electric generation resources that were procured by the IOU on their behalf.

In 2002 and subsequent years, the Commission adopted a series of decisions on the PCIA policies and methodologies pursuant to the statutory requirements. Recent major decisions on PCIA methodologies include D.21-05-030, D.22-07-008, and D.23-06-006.

Pub. Util. Code Section 380 requires that the "commission, in consultation with the Independent System Operator, shall establish resource adequacy requirements for all load-serving entities." In 2004, the Commission adopted an RA policy framework in order to ensure the reliability of electric service in California. We established RA obligations applicable to all Load Serving Entities (LSEs) within our jurisdiction, including IOUs, ESPs, and CCAs. The Commission's RA program guides resource procurement and promotes infrastructure investment by requiring that LSEs procure capacity so that capacity is available to the CAISO when and where needed.

The RA program now contains three distinct sets of requirements: System RA requirements (effective June 1, 2006), Local RA requirements (effective January 1, 2007) and Flexible RA requirements (effective January 1, 2015). Commission staff evaluate LSE filings annually and ensure accuracy and completeness monthly. Annual refinements to the RA program occur in rulemaking proceedings, the most recent of which was R.23-10-011.

3. Preliminary Scoping Memo

This rulemaking will be conducted in accordance with Article 6-Rulemaking of the Commission's Rules of Practice and Procedure (Rule or Rules). Pursuant to Rule 7.1(d), this Order Instituting Rulemaking (OIR) includes a preliminary scoping memo as set for below, and preliminarily determines the category of this proceeding and the need for hearing. Any respondents and/or party may respond to this preliminary list in comments on the proposed rulemaking. Pursuant to Rule 7.3, the Assigned Commissioner may change the scope of issues in their Assigned Commissioner Scoping Memo and Ruling (Scoping Ruling). The precise issues to be addressed and the process for addressing those issues will be set forth in the Assigned Commissioner's Scoping Memo. In order to focus the discussion, respondents and parties should structure their proposals to address the scoped issues.

3.1. Issues to Be Considered

This OIR will address issues related to the ERRA/PCIA procedures, rules, and proceedings. Section 3.1.1 identifies issues that will be heard on an expedited basis (Track One Issues). Those issues concern potential changes in the MPB calculation. Our goal in expediting that portion of the OIR is to allow the Energy Division to issue MBPs in October 2025 utilizing the new methodology if approved. Section 3.1.2 identifies the remaining issues to be considered in this OIR. (Track 2 Issues).

3.1.1. Issues for Expedited Consideration (Track One)

This OIR will consider on an expedited track potential modifications to the MPB calculations which could be adopted in time for Energy Division to produce the annual MPBs released on or near October 1st each year. Modification of the MPB methodology would need to be expedited because each large electric IOU's fall ERRA updates are due shortly thereafter. Timely adoption of each IOU ERRA filing is critical for updated rates to be implemented January 1st of next year. Rapid changes to the marginal price of RA have created a particular urgency to consider whether the current RA MPB formulation reflects the market value of the entirety of the IOU portfolio. Given the scale of impacts, the Commission will consider these issues on an expedited and/or interim basis in for potential incorporation into the 2026 ERRA forecast. The Commission will consider adopting some or all of the options in Track One, with the possibility of reviewing them again in Track Two:

1) ***Include all transactions available for given delivery year for all systems, flex, and local RA forecast and final adders.***

The forecast system and flexible resource adequacy (RA) MPBs only rely on the final year of transaction data, which results in setting a market value for the entire portfolio using the marginal price based on only recent transactions rather than on the average of all transactions for a given year. This is especially true when few transactions occur within the one-year timeframe. Transactions executed in the final year do not capture the weighted average of the entire portfolio because the MPB is reliant on only the most recent transaction data for a given delivery year. Likewise, the local forecast MPB uses three years of historical values, but this may not represent the average of all of the transactions for a given year, given that some local resources are under longer-term contracts. The Commission could consider using all transactions for a given year or all of the transaction data that is currently available (*i.e.*, the data that has been collected to date) to calculate a weighted average MPB that is more representative of a portfolio of resources procured ratably over time.

2) ***Exclude affiliate transactions from the calculation of the MPB.***

An affiliate transaction is a transaction between two affiliate corporate entities or subsidiaries, in which revenues from a transaction benefit the same parent corporation. An affiliate can be the marketing arm of that entity or a fully or partially owned subsidiary of the original entity. In the calculation of the 2025 Forecast and 2024 Final MPBs, Energy Division identified transactions between LSEs and their own affiliates or subsidiaries that were among the highest priced RA transactions. The Commission could consider whether transactions for resources owned or sold by an affiliate represent true "market-based" transactions and whether the affiliate could have sold the capacity to another entity in an arms-length transaction at the prices reported to Energy Division staff. The Commission could consider how to exclude these transactions from the MPB calculations.

3) ***Exclude swap and sleeve transactions from MPB.***

In the calculation of the 2025 Forecast and 2024 Final MPBs, Energy Division also identified swap and sleeve transactions with unusually high prices. A swap transaction is an exchange between two LSEs or an LSE and a marketer or generation owner of system, local or flex RA (*e.g.*, swapping system for local or system for flex RA) resource. For example, an LSE may exchange their system resources for local resources in their portfolio to enable each LSE to meet their obligations. Energy Division has observed that some of the reported transactions are for transactions with non-Commission jurisdictional entities that continue to have local obligations in the PG&E and SCE Transmission Access Charge areas. In these swap transactions, the overall price is less important than the For example, swapping 20 MW of system RA for local RA could report the system price at $25/kW-month and the local price at $30/kW-month, resulting in an additional cost of $5/kW-month for the local capacity. Likewise, this same transaction could be priced at $125/kW-month for the system and $130/kW-month for the local RA, with the same effect, a $5/kW-month premium for the local product. The Commission seeks comments on whether the unusually high prices of these swap transactions accurately reflect the market price, if the trading parties are only paying a modest premium for one of the products. The Commission seeks comments on whether and how to exclude these transactions from the MPB calculations, and whether and how to use these transactions differently in the calculation (*e.g.*, the above example is a data point that suggests the local RA price should be $5/kW-month greater than the system price).

Likewise, Energy Division identified a few sleeve transactions in the dataset, where one party appeared to be transacting on behalf of another. For example, Party A bought capacity at $25/kW-month but then sold that capacity at the same price (or a small premium) to another party in short order. The issue with sleeve transactions is that they could overweight this transaction, counting it as two transactions when it really represents only one. In a small dataset, this could overweight certain transactions and inflate the weighted average. The

Commission seeks comments on whether and how to consider a series of sleeve transactions to be a single transaction, when they are identified in the dataset.

4) Consider using monthly values for the MPBs.

RA prices fluctuate seasonally, primarily because there is typically excess capacity in the winter and shoulder seasons when loads are lower, and much less excess capacity, if any, during the summer season, when loads are typically much higher (California is a summer peaking region, with substantially higher loads in the summer months). As a result, RA capacity prices vary by as much as an order of magnitude across the months. The Commission seeks comments on whether and how to develop monthly or seasonal RA MPB values in order to more accurately estimate the cost of RA and the value of the utility portfolio. This would ultimately be used to estimate the price that bundled service customers should pay departing load customers for the use of retained assets and, likewise, the price that departing load customers should pay to bundled service customers for the uneconomic cost of the capacity that the utility procured on their behalf. The Commission see comments on whether to, in the alternative, calculate a monthly RA value for each month and then calculate a weighted average based upon transaction volume for each month.

5) Consider using one value for all MPBs, including system, local and flexible.

RA is a bundled product, where local and flexible RA capacity can be used to meet system RA compliance, but the majority of the capacity is categorized as local for the purpose of the MPB. Energy Division observed that only a small fraction of transactions from summer trades were classified as system RA MPB based on the location of the resource, while all RA market transactions were used to meet RA system compliance. This small fraction used in the system RA MPB represented only a narrow subset of the total traded volume of RA capacity. When calculating the MPB in previous years it may have made sense to separate out local RA prices, which were typically higher. Due to higher RA needs and fewer resources being available, system prices have also risen considerably, especially for a few select summer months (typically July, August and September). Since all RA capacity purchased meets system RA compliance, instead of just the narrow subset of resources that do not qualify as local and flexible RA, it may be more accurate to consolidate the RA attribute into a single MPB calculation. Given current market conditions, and that the local and flexible are bundled with system RA, the Commission seeks comments on whether to produce a single RA value for all of the attributes on a monthly basis using all available data for the year to attain the most robust dataset for calculating the MPB.

6) Placeholder proposals

Development of a revised MPB is likely to be contentious and could take a considerable amount of time. Therefore, the Commission may consider adopting an interim methodology for 2026, to be followed by a more complete reexamination of the methodology for the following year.

3.1.2. Other Issues for Consideration (Track Two)

The following issues will be considered under Track Two. The issues identified in Track One may also be revisited as part of the Track Two process.

1. Review of revisions to MPBs. This is expected to include methodological changes to the calculation, input data

rules, implementation and methodology application directions, and other changes that are adopted in Track 1. A preliminary focus on the RA MPB is expected due to specific data concerns raised by Energy Division staff regarding the RA MPB issued in October 2024. Further consideration may be necessary regarding the appropriate categorization of RA transactions as local, flex and system for the purpose of calculating RA MPBs.

2. Consideration of the need for ERRA-specific implementation guidance for RA program changes, including those related to the implementation of the Slice of Day framework, as was raised in the 2025 ERRA forecast. This issue would exclusively focus on ERRA guidance for the implementation of rules adopted in the RA proceeding and would not extend to any issues in scope for that proceeding.

3. Consideration of whether changes to Bundled Procurement Plan directions, processes, and rules are necessary and justified, or whether complementary or replacement guidance for procurement activity review in ERRA compliance cases is necessary. Issues regarding sufficiency of BPPs have been repeatedly raised in individual ERRA proceedings, focusing on questions about whether IOU management of procurement activities is reasonable and compliant with Commission rules.

4. Consideration of improved PCIA and ERRA mechanisms to reduce rate volatility, possibly including adjustments to trigger mechanisms and processes. We also intend to consider whether rules to improve utility forecasting should be created, including possible incentive mechanisms.

5. Consideration of additional guidance for vintaging resources, especially with respect to changes to or investments in utility owned resources.

3.2. Preliminary Schedule

The preliminary schedule for this rulemaking is set forth below and includes the provisions for the filing of comments on the OIR. The schedule adopted here may be modified by the assigned Commissioner and Administrative Law Judge (ALJ) as required to promote the efficient and fair resolution of the rulemaking. Today's decision establishes the dates for opening and reply comments. The final schedule will be adopted in the Assigned Commissioner's Scoping Memo. Each of the issue areas outlined in the Preliminary Scoping Memo will likely require different types and degrees of public participation. Therefore, we delegate further definition of procedure and schedule for each issue area to the Assigned Commissioner and ALJ as determined in the Scoping Ruling or a later ruling.

Opening comments on the OIR by interested parties shall be filed and served not later than 20 days after the issuance of this OIR. Reply comments shall be filed and served not later than 35 days after the issuance of this OIR. As noted above, this OIR will proceed in two phases, Track One and Track Two. Section 3.1.1 identifies staff proposals for resolving Track One. Interested parties are directed to address those proposals in their opening and reply comments on the OIR.

The Assigned Commissioner will hold a prehearing conference (PHC) and, following the PHC, issue a Scoping Memo and Ruling adopting a schedule for Track One. The PHC will be held for the purposes of 1) taking appearances, 2) discussing schedule and process, 3) discussing the issues in scope, and 4) informing the scoping memo. It is anticipated that a proposed decision on Track One will be issued in May 2025.

There may also be workshops in this proceeding. Notice of such workshops will be posted on the Commission's Daily Calendar to inform the public that a decisionmaker or an advisor may be present at those meetings or workshops. Parties should check the Daily Calendar regularly for such notices.

4. Categorization of Proceeding and Need for Hearing

This proceeding is preliminarily categorized as a ratesetting. For ratesetting matters, Pub. Util. Code § 1701.5(a) requires that:

> … the commission shall resolve the issues raised in the scoping memo within 18 months of the date the proceeding is initiated, unless the commission makes a written determination that the deadline cannot be met, including findings as to the reason, and issues an order extending the deadline.

Pursuant to Pub. Util. Code Section 1701.5(a) and based upon the complexity of issues preliminarily identified in this rulemaking and the anticipated need to coordinate with multiple other proceedings, we find that this rulemaking cannot be resolved in 18 months. As such, the statutory deadline for this proceeding is set at 36 months from the date this OIR is issued.

At this time, we do not anticipate a need for hearings.

5. *Ex Parte* Communications

Because this proceeding has been preliminarily categorized as ratesetting, *ex parte* communications are restricted and must be reported pursuant to Article 8 of the Rules.

6. Respondents

Respondents to this OIR shall be:

- PG&E;
- SCE;
- SDG&E;
- All CCAs (*see* Appendix A); and
- All ESPs (*see* Appendix B).

The small and multijurisdictional utilities--PacifiCorp, Bear Valley Electric Service, and Liberty Utilities (CalPeco)--are not made respondents, but are encouraged to become parties and participate in this proceeding. Similarly, CAISO is not made a respondent, but shall be provided a copy of this OIR and the opportunity to participate. All Respondents must, and any interested persons may, comment on the preliminary scoping memo consistent with the schedule established in Section 3.

7. Service of OIR

This rulemaking will be served on the Respondents and entities identified in Section 6 and on the service lists indicated below. Service of the rulemaking does not confer party status or place any person who has received such service on the official service list for this proceeding, other than Respondents. Persons who file responsive comments become parties to the proceeding and will be added to the "Parties" category of the official service list upon such filing.

This OIR will be served on the Official Service Lists for the following proceedings:

- R.14-07-002;

- R.14-10-010;
- R.15-02-020;
- R.16-02-007;
- R.17-06-026;
- R.18-07-003
- R.23-10-011
- R.24-01-017
- Application (A.) 22-02-015
- A.22-05-022;
- A.22-05-023;
- A.22-05-024;
- A.22-05-024;
- A.22-05-029;
- A.23-05-012;
- A.22-06-001;
- A.23-06-002;
- A.23-07-012;
- A.24-03-018;
- A.24-04-010;
- A.24-05-007;
- A.24-05-009;
- A.24-05-010; and
- A.24-08-002.

To ensure service of comments and other documents and correspondence in advance of obtaining party status, persons should promptly request addition to the "Information Only" category as described below; they will be removed from that category upon obtaining party status. Any person will be added to the "Information Only" category of the official service list upon request, for electronic service of all documents in the proceeding, and should request to do so promptly in order to ensure timely service of comments and other documents and correspondence in the proceeding.[6] The request must be sent to the Process Office by e-mail (process_office@cpuc.ca.gov) or letter (Process Office, California Public Utilities Commission, 505 Van Ness Avenue, San Francisco, California 94102). Please include the Docket Number of this rulemaking in the request.

8. Subscription Service

Interested persons may monitor the proceeding by subscribing to receive electronic copies of documents in this proceeding that are published on the Commission's website. There is no need to be on the official service list in order to use the subscription service. Instructions for enrolling in the subscription service are available on the Commission's website at http://subscribecpuc.cpuc.ca.gov/.

9. Filing and Service of Comments and Other Documents

Article 1 of the Rules governs the filing and service of comments and other documents in this proceeding. (*See* particularly Rules 1.5 through 1.10 and 1.13.) If you have questions about the Commission's filing and service procedures, contact the Docket Office (Docket_Office@cpuc.ca.gov) or check the Practitioner's Page on our website at https://www.cpuc.ca.gov/.

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[6] Rule 1.9(f).

When serving any document, each party must ensure that it is using the current official service list on the Commission's website.

This proceeding will follow the electronic service protocol set forth in Rule 1.10. All parties to this proceeding shall serve documents and pleadings using electronic mail, whenever possible, transmitted no later than 5:00 p.m., on the date scheduled for service to occur. Rule 1.10(d) requires that "the serving person must provide a paper copy of all documents served by e-mail service to the assigned Administrative Law Judge (or, if none is yet assigned, to the Chief Administrative Law Judge), unless the Administrative Law Judge orders otherwise." In this proceeding, parties are excused from serving the ALJ with hardcopy (paper copy) of the electronic filed or served documents.

When serving documents on Commissioners or their personal advisors, whether or not they are on the official service list, parties must only provide electronic service. Parties must not send hard copies of documents to Commissioners or their personal advisors unless specifically instructed to do so.

Persons who are not parties but wish to receive electronic service of documents filed in the proceeding may contact the Process Office at process_office@cpuc.ca.gov to request addition to the "Information Only" category of the official service list pursuant to Rule 1.9(f).

The Commission encourages those who seek information-only status on the service list to consider the Commission's subscription service as an alternative. The subscription service sends individual notifications to each subscriber of formal e-filings tendered and accepted by the Commission. Notices sent through subscription service are less likely to be flagged by spam or other filters. Notifications may be established for a specific proceeding, a range of documents and daily or weekly digests.

10. Intervenor Compensation

Intervenor compensation is permitted in this rulemaking. Any party that expects to claim intervenor compensation for its participation in this rulemaking must file its notice of intent to claim intervenor compensation within 30 days of the filing of reply comments, except that notice may be filed within 30 days of a PHC in the event that one is held. (*See* Rule 17.1(a)(2).) Intervenor compensation rules are governed by Pub. Util. Code § 1801 et seq. Parties new to participating in Commission proceedings may contact the Commission's Public Advisor for assistance.

11. Public Advisor

Any person or entity interested in participating in this rulemaking who is unfamiliar with the Commission's procedures should contact the Commission's Public Advisor in San Francisco at 1-415-703-2074 or 1-866-849-8390 or email (public.advisor@cpuc.ca.gov). The TTY number for the Public Advisor is 1-866-836-7825.

O R D E R

IT IS ORDERED that:

1. The preliminary categorization is ratesetting.
2. The preliminary determination is that a hearing is not required.
3. The preliminary scope of issues is as set forth in Section 3.1 and is adopted.
4. The preliminary schedule for this proceeding is as set forth in Section 3.2 and is adopted.

5. The Executive Director will cause this Order Instituting Rulemaking to be served upon all Respondents and entities identified in Section 6 and the service lists identified in Section 7.

6. Any party that wishes to claim intervenor compensation for its participation in this rulemaking must file its notice of intent to claim intervenor compensation within 30 days of the prehearing conference (*See* Rule 17.1(a)(2)) of the California Public Utilities Commission's Rules of Practice and Procedure).

7. Parties are excused from Rule 1.10(d) of the California Public Utilities Commission's Rules of Practice and Procedure requirement regarding service of paper copies upon the assigned Administrative Law Judge and shall avoid serving any paper copy of documents electronically filed or electronically served.

This order is effective today.

Dated February 20, 2025, at Sacramento, California.

ALICE REYNOLDS
President
DARCIE L. HOUCK
JOHN REYNOLDS
KAREN DOUGLAS
MATTHEW BAKER
Commissioners

APPENDIX A
Community Choice Aggregators (CCAs)

Community Choice Aggregators (CCAs)

- Apple Valley Choice Energy
- Central Cost Community Energy
- City of Palmdale
- Clean Energy Alliance
- Clean Power Alliance of Southern California
- CleanPowerSF
- Desert Community Energy
- East Bay Community Energy
- King City Community Power
- Lancaster Choice Energy
- Marin Clean Energy
- Orange County Power Authority
- Peninsula Clean Energy Authority
- Pico Rivera Innovative Municipal Energy
- Pioneer Community Energy
- Pomona Choice Energy
- Rancho Mirage Energy Authority
- Redwood Coast Energy Authority
- San Diego Community Power
- San Jacinto Power
- San José Clean Energy
- Santa Barbara Clean Energy
- Silicon Valley Clean Energy Authority
- Sonoma Clean Power Authority
- Valley Clean Energy Alliance

(END OF APPENDIX A)

APPENDIX B

Energy Service Providers (ESPs)

Energy Service Providers (ESPs)

- 3 Phases Renewables
- Calpine Energy Solutions, LLC
- Calpine Power America-CA, LLC
- Commercial Energy of Montana
- Constellation NewEnergy, Inc.
- Direct Energy Business, LLC
- "BP Energy Retail Company California, LLC
- (EDF Industrial Power Services (CA), LLC)"
- GEXA ENERGY CALIFORNIA, LLC
- PALMCO POWER CA
- Pilot Power Group, LLC
- Praxair Plainfield, Inc.
- "Shell Energy North America
- dba Shell Energy Solutions"
- TENASKA POWER SERVICES CO.
- The Regents of the University of California
- Tiger Natural Gas, Inc.
- Brookfield Renewable Energy Marketing US LLC
- Just Energy Solutions, Inc

(END OF APPENDIX B)