Price Process Review

for
The Board of Directors of
Salt River Project
Agricultural Improvement and Power District

By

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Christensen Associates Energy Consulting, LLC

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EXECUTIVE SUMMARY

The Board of Directors of Salt River Project (SRP) engaged Christensen Associates Energy Consulting (CA Energy Consulting) to review objectively SRP Management's documentation supporting a price process submitted to the Board for its evaluation and approval. Management has applied to increase rates overall by 2.4%, with a base increase of 4.0% and a reduction in the Fuel and Purchased Power Adjustment Mechanism (FPPAM) of 1.6%.[1] The Board seeks a review of management's price proposals with respect to their conformity with the general costing and pricing principles of sound utility management, and with SRP's own strategic and pricing objectives.

The price proposal documentation under review consists of three studies.

- The Cost Allocation Study (CAS) has the purpose of distributing the financial costs of the utility attributable to retail customers to its retail rate classes.
- The Marginal Cost Study (MCS) estimates the costs of incremental changes in customer behavior to the utility. Such cost estimates are important for SRP's decision making and for customer decisions regarding energy consumption in the short term and energy end use decisions in the long term.
- *"Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle"* (the *Proposed Adjustments* document") presents the utility's rate designs. The proposed adjustments include both changes in rate structure and modifications in prices to achieve the utility's rate objectives.

This review examines these three documents and provides commentary to the Board regarding their ability to perform the required tasks, and regarding the price proposals' success in meeting the Board's objectives.

[1] SRP, *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle*, December 2, 2024, p. 2.

ES 1. Cost Allocation Study

A successful CAS must fully allocate a utility's financial costs adhering to the established principle of cost causation: costs should be allocated to the customers who cause the costs to occur. The methods growing out of this principle consist of three main steps: functionalization, classification, and allocation.

- Functionalization organizes the utility's costs by function: generation or production, transmission, distribution, and general/customer service.

- Classification organizes costs within each function by cost causative factor: customer-related, demand-related, and energy-related.

- Allocation organizes costs within each classification by rate class.

The output of a CAS is the allocation of the utility's forecasted test year revenue requirement to retail rate classes. Additional information includes a comparison of revenues to costs by class, so that the rate designer can assess the degree to which rates are charged equitably in terms of cost coverage.

Management's CAS performs these tasks. This price process includes modifications to CAS methodology and improvement in information used to classify costs.

- **FPPAM cost classification.** Management proposes to classify these costs as partly demand-related and partly energy-related, reflecting the increase in demand charge share of purchased power costs.

- **Distribution cost classification.** Management has used newly available internal utility data on operation and maintenance costs to classify distribution costs as partly demand-related and partly customer-related. (That is, the methodology remained unchanged, but the data sources underpinning the split improved.)

- **Demand-related cost allocation.** For FPPAM and generation demand costs, Management proposes using a loss of load probability-weighted allocator instead of the traditional coincident peak allocator. This change reflects the fact that demand-related costs now are most closely related to market reserves conditions, which are tightest in the evening, when solar production has declined but customer consumption is still high.

Management has also implemented a customer cost smoothing process for the Residential and General Service classes, reflecting cost changes and an agreement to equalize charges within class. The calculation of rate of return by class does not include this smoothing.

<u>CA Energy Consulting Assessment:</u>

- Management's CAS methodology reflects costing theory and industry practice.

- Management's proposed modifications to methodology and data sources respond to changing circumstances and are consistent with industry practice.

- Management's customer cost smoothing is a rate design calculation rather than a cost allocation calculation but it is practical to perform the calculations within the CAS.

Calculation of rate of return by class in the absence of smoothing facilitates proper decision making regarding overall revenue requirements by class.

ES 3. Marginal Cost Study

The task of a marginal cost study is to provide the utility with an understanding of how its costs change as customer behavior changes. This behavior is typically observable as changes in the number of customers, the level of peak demand, and in overall consumption per period. The study usually develops marginal costs of the three main functions, generation, transmission, and distribution, by cost causative factor. Estimates rely on a variety of methodologies.

- **Marginal energy costs.** Generation marginal cost estimates refer to costs observable in wholesale energy markets. Transmission and distribution costs rely on technical estimates of line losses.

- **Marginal demand costs.** Generation demand-related costs are based on estimates of the value of capacity, discoverable from the market values of peaking capacity, in this case a combustion turbine generator, solar generation, and battery storage. Transmission and distribution demand-related costs rely on evidence from historical investments to meet load growth. The methodology relies on computation of economic carrying charges, which result in annualized cost estimates of multi-year investments.

- **Marginal customer costs.** These costs are concentrated in the distribution function, consisting of metering, billing, and customer services. Review of historical data provides estimates of incremental costs.

CA Energy Consulting Assessment:

- Management's methods are well established and conform to economic theory and industry practice.

- The computations of the various cost components under the familiar methods make use of contemporary information, both from market estimates and internal data.

ES 3. Rate Design Proposals

A successful rate design satisfies rate design criteria first set out by James Bonbright.[2] These criteria include revenue sufficiency, price efficiency, fairness, and revenue stability, among others. SRP has made explicit its own strategic rate objectives that overlap with the Bonbright principles. These five principles are: 1) Sufficiency (revenue adequate to cover costs); 2) Cost Relation (prices for each class associated with the cost to serve that class, by cost causative factor), 3) equity (perceived fairness in costing and pricing), 4) Choice (rate alternatives to support diverse customer needs and preferences), and 5) Gradualism (avoidance of large changes in bills, with moderate changes in rates toward new cost-based levels over time).

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[2] J.C. Bonbright, A.L. Danielson, D.R. Kamerschen, *Principles of Public Utility Rates*, c. 1968, Public Utility Reports, Inc. pp. 382-384.

SRP's current rates predominantly utilize seasonal pricing of energy and demand, with time-of-use (TOU) energy segmentation to convey the time pattern of generation services costs paid by the utility. An exception to this structure is the most popular seasonal Residential rate, which currently has an inclining block design. (That is, the energy price beyond 2,000 kWh per billing period is higher than the price for the first 2,000 kWh.) This latter structure strives for simplicity in not using the TOU pattern found elsewhere.

Management's proposal updates the rate structure in two ways.

- **TOU pricing periods.** Management proposes to move the peak period from the afternoon to the evenings, reflecting the emerging change in the pattern of wholesale market prices resulting from the spread of solar generation. The off-peak period moves to the daytime.
    - Management proposed to make this change for General Service and Large General Service customers with the November 2025 effective date for new rates.
    - Management further proposes to open new Residential rates with these time period changes at that time. It proposes freezing the existing TOU rates to new customers, and allowing customers until November 2029 to adopt a new rate of their choice.
- **Customer charge levels.** Management proposes addressing the traditionally low level of monthly customer charges relative to customer-related costs by increasing monthly customer charges relative to other prices. The effect of this proposal is to achieve a better match between customer fixed charges and customer-related fixed costs. Compensating reductions in the rate of increase of energy charges, bringing energy prices closer to energy-related costs improve price efficiency.

<u>CA Energy Consulting Assessment:</u>

- Management's proposals regarding TOU time period changes and increased customer charges respond to changing cost conditions. These recommendations help to produce an improved match, both between classes and within class, between a customer's bills and their cost to serve.
- Management has computed bill impacts reflecting the proposed price changes, by rate class and by stratum within class. Bill impacts are largely moderate in nature, with most customers having bill changes clustered around the average for the class.
    - For customers with larger increases, the impacts reflect, to some degree, reductions in cross subsidy that have existed previously.
- The changes also move prices in the direction of price efficiency, which will offer customers improved guidance in energy use decision making in the future.

ES 4. Summary of Findings

Management's price proposals are based on sound embedded and marginal cost principles and practices. The proposals also respond to rate design challenges that have been emerging since the previous price process. These proposals largely meet the Board’s strategic pricing objectives and general criteria for successful rate design.

Overall, Management’s price proposals satisfy the general criteria for a successful rate design since they provide not only for revenue sufficiency and rate design acceptability, but also improved price efficiency, rate stability (since the structures are not changing much other than the price period timing), and fairness (since the degree of cross subsidy is being reduced via the monthly customer charge increases). CA Energy Consulting finds that Management’s proposals meet these rate design requirements and provide satisfactory cost support for the utility’s price structure and price level recommendations.

1. INTRODUCTION

The Board of Directors of Salt River Project (SRP) engaged Christensen Associates Energy Consulting (CA Energy Consulting) to review objectively SRP Management's documentation supporting a price process submitted to the Board for its evaluation and approval. Management has applied to increase rates overall by 2.4%, with a base increase of 4.0% and a reduction in the Fuel and Purchased Power Adjustment Mechanism (FPPAM) of 1.6%.[3] The Board seeks a review of management's price proposals with respect to their conformity with the general costing and pricing principles of sound utility management, and with SRP's own strategic and pricing objectives.

A price process is triggered by awareness that the utility is either over- or under-earning relative to its financial objectives, or by the passage of time since the previous price process. On this occasion, the last price process was five years ago, in 2019, and the rate of return has fallen. As Management's *Proposed Adjustments* document states, significant changes in costs and in the regional economy during the recovery from the COVID pandemic have necessitated the initiation of a new price process.[4]

The price process involves three analytical stages. First, the Cost Allocation Study (CAS) applies the utility's costing practices to distribute embedded (i.e., financial) costs to the various retail rate classes. (Wholesale, telecom, water, and lighting equipment costs are excluded from the allocation.) Second, Management prepares a Marginal Cost Study (MCS) to update its knowledge of how costs change if consumption, peak demand, or the number of customers changes. Such marginal costs are useful for decision making and contribute to price development once financial costs are allocated to class. Third, with embedded and marginal cost information in hand, Management develops new prices for existing rates, and designs and prices new rate options to meet changing customer needs.

This review encompasses each of these three stages. Management's price proposals need to satisfy standards set by theory and industry practice and contribute to meeting the Board's objectives for ratemaking. With respect to the CAS study, the overall standard is to meet the requirements of full allocation – all financial costs are allocated to classes – and to respect the principle of cost causation. That principle states that costs should be assigned or allocated to customers, or customer classes, that cause the cost to be incurred. More generally, CAS studies have a host of allocation practices guiding the analyst in determining which customers pay for each type of cost. The *NARUC COS Manual* is still the central guide to these principles.[5]

With respect to the marginal cost study, the central objective is to ensure that the estimated incremental costs of any change should be comprehensive, so that management decisions are guided by an understanding of the "all-in" costs of a change in the number of customers, the

[3] SRP, *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle*, dated December 2, 2024, p. 2.
[4] *Ibid*, p. 2.
[5] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January 1992.

amount of consumption, or the level of peak demand. The analyst must also observe and be guided by a number of methodological requirements.

With respect to rate design, Management pricing and rate structure decisions can use as criteria for successful rate design the well-known Bonbright principles.[6] These criteria include revenue sufficiency, price efficiency, fairness, and revenue stability, among others. SRP has made explicit its own strategic rate objectives that overlap with the Bonbright principles. The SRP Board Pricing Principles are:

- **Sufficiency:** prices must recover sufficient revenues to maintain the utility's financial health.
- **Cost Relation:** prices must reflect the cost of service (as set out by the CAS, but also making use of marginal cost indicators, where appropriate).
- **Equity:** prices should be perceived as fair by customers.
- **Choice:** customer diversity of end uses and energy management preferences should be recognized in rate alternatives that assist customers to meet their energy goals and to control costs.
- **Gradualism:** customers' bills should not be subjected to large increases but should instead evolve to new cost-based levels over time.[7]

Meeting these objectives involves trade-offs. Cost relation, for example, comes into conflict with the objective of gradualism should costs or cost allocation methods change. Pricing for revenue recovery can produce prices that do not reflect marginal cost, inducing inefficient consumption decisions by customers and possibly inefficient investment decisions by the utility. This review will examine how Management's rate design proposals balance these multiple objectives in striving to meet customer needs subject to the requirement to maintain financial health for the utility.

The rest of this report comprises three sections covering Management's CAS, MCS, and rate design proposals. A summary of our findings concludes the report.

2. COST ALLOCATION STUDY

2.1 Overview of SRP's Cost Allocation Study

SRP's CAS performs the tasks of distributing the financial costs of the utility across its retail rate classes according to an established set of cost allocation rules practiced by regulated electric utilities.[8] (Regulation is typically undertaken by a state regulator for investor-owned utilities, and by boards of directors or other oversight committees for public sector utilities, which can be

[6] J.C. Bonbright, A.L. Danielson, D.R. Kamerschen, *Principles of Public Utility Rates*, c. 1968, Public Utility Reports, Inc. pp. 382-384.

[7] SRP, *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle*, dated December 2, 2024, p. 27.

[8] SRP, *Cost Allocation Study in Support of Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle*, December 2, 2024.

municipal, rural electric cooperatives or large federally supervised institutions such as the Bonneville Power Authority.)

SRP has selected a forecast test year (May 2025 – April 2026) as its basis for cost estimation. Forecast test years are one of three recognized approaches to test years, the others being historical and hybrid (part historical, part forecast). Forecast test years are common in the industry and it is reasonable for SRP to use this approach. The advantage of the forecast test year approach is an improved ability to match costs and billing quantities used in allocation to the initial period when rates will apply. The disadvantage is the greater need for the utility to use forecasting to develop data inputs to the study and a resulting increased challenge for stakeholders reviewing the study to evaluate the CAS analysis. Regulators in other jurisdictions are aware of these characteristics and the forecast test year approach has long been accepted.

SRP adopts an approach to revenue requirements that is common in public power. This approach is commonly labeled the "cash" method. Revenue requirements consist of current expenses, debt service and cash requirements for upcoming investment. The alternative approach is labeled the "accruals" method and formulates revenue requirements as rate base multiplied by allowed rate of return plus current expenses. In both cases, taxes and account items such as construction work in progress (CWIP) adjust those requirements. Both approaches are well established and reasonable.

In preparing a CAS, analysts acquire financial data for the utility as a whole and first functionalize these financial costs, categorizing them by the utility's main functions. In a vertically integrated utility like SRP, these functions consist primarily of generation/production, transmission, distribution, and customer service. The second step is classification within each function by cost causative factor. These factors are chiefly customer, demand, and energy causation. That is, costs are deemed to change in response to changes in the number of customers, level of peak demand, or total consumption of energy. The third step is allocation of common costs to class, with different types of allocators applying to cost causative factors.[9]

Within these three steps, the analyst strives to ensure that costs assignable to individual customers or classes are separated prior to classification. Additionally, it is advisable to separate costs by voltage service level (VSL) so that customers at a high VSL do not have to pay costs associated with lower VSLs. For example, transmission service customers are not responsible for distribution-level costs.

SRP's CAS model combines the steps of functionalization and classification at the same time, rather than conducting them sequentially. The study distributes costs across ten categories, plus two separate categories for FPPAM costs. The approach of simultaneous functionalization and classification is well established in cost-of-service modeling practice. The model allocates costs via allocators similar to those found in other models. Costing methodology permits a wide variety of allocators to be used, and tailoring allocators to utility circumstances is standard.

[9] A traditional point of confusion is that the process of distributing costs to rates is called allocation, with the term used as an umbrella for all the work of creating a CAS. The term "allocation" is also the third main step in that process: it consists of sharing costs that have been functionalized and classified across retail rate classes.

CA Energy Consulting Assessment:

- Management's use of a forecast test year is appropriate and is in widespread use in the industry.

- The cash approach to determining revenue requirements is appropriate for a publicly owned utility like SRP. When combined with the use of a forward test year, it appropriately anticipates the utility's cash needs and incorporates those needs into revenue requirements.

- Management's CAS model reflects its costing methodology, and its general process of functionalizing, classifying, and allocating costs appears to comport with industry standards.

2.2 Functional Classification

2.2.1 General Approach

SRP functionalizes and classifies its expenses in conventional fashion but has introduced some refinements for this process. The functional classes found in Schedule 1 cover generation, transmission, distribution, and customer service functions that are recognized in other jurisdictions. These functions have classifications that might be constructed as follows were the SRP structure to be aligned with that of other utilities:

- Generation
    - Generation (fixed costs) (combination of demand- and energy-related)
    - Fuel and Purchased Power Adjustment
        - Demand-Related
        - Energy-Related
    - Ancillary Services (combination of demand- and energy-related)
- Transmission (demand-related)
- Distribution
    - Dedicated (directly assigned)
    - Facilities (customer-related)
    - Delivery (demand-related)
- Customer Services (customer-related)
    - Billing and Customer Service
    - Metering
- System Benefits (energy-related)

SRP does not denote its functional classifications exactly in this manner, but the list indicates that its approach is in line with that of other utilities and costing theory. Longstanding practice, as set out in the *NARUC COS Manual*, offers a wide range of classification alternatives to the utility. For generation services, the analyst can choose between demand-only and a combination of demand and energy classification.[10] SRP does the latter, as evidenced by its utilization of the

[10] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January 1992, See Chapter 4.

Peak and Average method of cost allocation, a method which shares costs between demand- and energy-related cost causation.[11]

Transmission services are usually classified as demand-related, after subfunctionalization of some transmission costs as generation- or distribution-related. This approach reflects the common perspective that the bulk transmission grid must be constructed to meet the highest level of system load. Other approaches are possible. SRP adopts the conventional demand-related classification approach.

Distribution services are typically deemed customer- and demand-related in terms of cost causation. Intuitively, any customer site requires equipment and services that do not vary with customer size, within the customer class. An example is meters: one per customer usually suffices. Other costs must be sized to meet peak demand, this time measured at the individual customer, feeder line, or customer class level. Utility analysts have developed a range of computational methods to estimate the shares of these cost causative factors. SRP is changing its supporting classification data with this price process. A discussion of that change appears below.

System benefits might be thought of as part of customer services but the costs associated with this category do not fit well with customer- or demand-related causation. SRP classifies these as energy-related. This approach is common elsewhere in the industry and is often expressed in an adjustor that is billed based on monthly consumption.[12]

It might also be mentioned that SRP's expenses as functionalized and classified in the CAS are drawn from an appropriate source, Fiscal Year 2026 of SRP's 2025 Financial Plan.[13] Additionally, the CAS excludes non-retail costs and revenues. Other utilities do this, while some include wholesale sales as an additional rate class. SRP's approach is reasonable.

Management's description of functional classification provides detail on certain expense accounts that do not readily fit into the main expense accounts. [14] In these cases, it is not obvious how classification ought to be done. The study identifies and classifies the following accounts:

- **Financing costs and contributions to future capital:** functionally classified according to the functional classification shares of the capital budget.
- **Interest income:** functionally classified in proportion to non-passthrough revenues.
- **Other income and deductions:** functionally classified as generation (fixed cost) since it is chiefly a tax credit on a generation unit. A residual, related to pensions, is functionally classified in the same manner as O&M costs. (That is, this is an example of an indirect classification based on the previously established classification of other costs.)

[11] SRP, *Cost Allocation Study in Support of Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle*, December 2, 2024, p. 2.

[12] Technical note: SRP uses the terms "adjustor" and "rider" while the industry typically uses only (or predominantly) the latter. SRP's distinction is that a rider is a price component for which prices are set in a formal price process while an adjustor is a price component that can be revised from time to time between price processes. The best-known example of such an adjustor is the FPPAM, which SRP adjusts annually, for the most part, but can update with Board approval more frequently in instances of fuel or purchased power price volatility.

[13] SRP, *Cost Allocation Study in Support of Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle*, December 2, 2024, p. 1.

[14] Ibid, pp. 4-5.

- **Electric revenue contributions to water operations:** functionally classified based on operating expenses.
- **Revenue credits:** functionally classified mostly as generation, with a residual as system benefit.
- **FPPAM Balance true-up:** functionally classified as energy-related.[15]

Each of these functional classification decisions appears to be the application of previous methods and can be supported by means of common sense by association with similar costs. Electric revenues transferred to the water practice must rely on some means of allocation, and the use of operating expenses for functional classification appears judicious and preferable to a revenue-based or some other classification device. On balance, these practices appear sensible and can rely on support from practice elsewhere.

<u>CA Energy Consulting Assessment:</u>

- Management's general approach to cost functionalization and classification as a single step are in line with industry practice and reflect costing theory as set out in the *NARUC COS Manual*.
    - The functional classification categories appear to match well with those of other utilities.
- The functional classification of miscellaneous accounts appears sensible.

2.2.2 Modifications to Functional Classification Methods

An important modification in the classification process is documented in Management's CAS Study is the separation of the Fuel and Purchased Power Adjustment classification into two components, one energy-related and the other demand-related. Previously, as noted in the CAS study, all such costs were treated as energy-related. This previous approach is in wide use in the industry. Management's position is that changes in the structure of purchased power agreements in the direction of separate demand and energy charges provides the opportunity to reflect demand-related costs in its CAS classification.[16]

This change brings the treatment of variable operating expenses recovered via an important adjustor in line with expenses in the CAS's other areas of expenses by reflecting cost causation in an improved manner than previously.

A second modification in CAS functionalization and classification methodology arises from SRP's collection of data to support the classification of distribution costs as customer- and demand-related. Previously, the utility had relied on a "special distribution study" to classify its distribution costs. A new survey of distribution new jobs data covering the period beginning FY 2020 is now available to conduct this classification. This revised approach offers greater

[15] With conversion of the FPPAM balance to a combination of energy and demand causation, it may be sensible in the future to classify this account in the same manner. For the moment, though, the balance consists of costs incurred at a time when the classification was energy-related exclusively.
[16] SRP, *Cost Allocation Study in Support of Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle*, December 2, 2024, pp. 1-2, also p. 8.

precision in classifying costs as Distribution Facilities (customer-related costs) and Distribution Delivery (demand-related costs).[17]

Other utilities, especially those that formulate revenue requirements as the product of rate base and rate of return plus O&M expenses, conduct studies of rate base or gross plant to classify distribution assets as customer- and demand-related, and then apply those shares to expenses. Since SRP constructs its revenue requirement as the sum of expenses, debt service and cash investment requirements, it adopts a different methodology for distribution cost classification than do investor-owned utilities with rate base-oriented revenue requirement calculations. SRP's method is appropriate given its approach to developing revenue requirements.[18] The methodology improvement for distribution cost classification appears appropriate, as it based on improved and timely data.

<u>CA Energy Consulting Assessment:</u>

- SRP's proposed modifications to functional classification appear judicious and improve the reflection of cost causation in that classification.
    - In particular, the segmentation of FPPAM classification into demand and energy components appears to improve cost causation for a large area of costs.
    - Similarly, distribution cost classification has been improved by means of the use of improved data on O&M costs as a gauge of the cost splits between customer and demand causation.

2.3 Cost Allocation

2.3.1 General Approach

Management allocates functionally classified costs largely according to industry practice, using allocators based on the number of customers, level of demand, and amount of energy consumption associated with each class as a sharing mechanism. The number of allocators is small relative to other utilities, perhaps due to the use of the cash basis of revenue requirements, and the CAS model documents in detail the means by which allocators are constructed. This can be taken for granted but to an outside reviewer, this transparency serves to build confidence in the model's calculations and the accuracy of cost allocation.

The allocators developed in the model are mostly traditional and comparable to those used in other embedded cost allocation studies. For example, transmission costs, which are demand-related, are allocated by a 4CP (4-month coincident peak) allocator. CP allocators are commonly used to reflect time periods when the bulk transmission system (and, historically, generation)

[17] SRP, *Cost Allocation Study in Support of Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle*, December 2, 2024, p. 8.
[18] CAS Schedule 2 presents the approach.

peaks. The four months in this case are the four summer months, reflecting the fact that SRP is a summer-peaking system.[19]

Similarly, demand-related distribution (Distribution Delivery) costs are allocated by means of a 1NCP allocator. That is, the share of each class is determined by summing the highest point of demand in the year for each class across all classes, regardless of when each class's usage peaks. This allocator is a common proxy for representing demand peaks on the distribution system, say, at the level of the feeder line in a residential neighborhood.

Management has introduced some new approaches to cost allocation with the intention of adapting cost allocation to changing circumstances. The next section reviews some of these changes. Stable cost allocation, and thus stable rates, benefit from the retention of stable allocators over time. Most utilities rarely alter allocators for this reason. However, allocators are proxies for the utility analyst's beliefs about what best represents the share of costs, and from time to time the accuracy of proxies can be called into question. In such cases, it is in the interest of the utility and its customers to review and revise an allocator.

Allocators are also necessary to apportion net plant in order to be able to formulate rate of return by class, at both existing and proposed revenue requirements. The CAS methodology applies the same allocators as those used in O&M costs to allocate costs for the net plant organized by functional classification. This approach is standard in cost allocation and reflects the belief that the equipment and the operating costs of a functional classification should be treated similarly.

CA Energy Consulting Assessment:

- The cost allocation methodology as presented in Management's CAS document in largely in line with industry practice and with cost allocation theory.

- Allocators continued from the previous price process are recognized conventional representations of cost sharing practices.

2.3.2 Allocation of Expenses

2.3.2.1 Generation

Management continues to use the same allocators as those used in previous price processes for several types of costs. However, in several cases, management is proposing a change in methodology. Two of these changes occur in the generation function. This function consists of two subfunctions, fuel and purchased power, whose costs are recovered in the FPPAM, and generation capital costs. Management proposes to split the FPPAM category into two components, one classified as energy-related (previously the classification of all FPPAM costs) and the other classified as demand-related.

Management argues that the FPPAM split is advisable due to the increasing share of purchased power costs that have a demand component. As such, proper cost classification involves treating these demand-related costs as being attributable to costs caused by customers' coincident peak

[19] SRP, *Cost Allocation Study in Support of Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle*, December 2, 2024, p. 56.

demands. Traditional utility practice has involved treating fuel and purchased power expenses as recoverable in adjustors, due to the ability to modify pricing between rate (price revision) applications. In the past, these adjustors had prices denominated in $/kWh only and were classified implicitly as being energy-related only. However, the move to a combination of demand and energy in cost allocation makes sense, especially in SRP's case, since the amounts are sizeable and the demand component is increasingly important. Furthermore, calculating the energy and demand shares of costs is not difficult, and the allocators to share costs to class are already readily available. In brief, costing theory suggests this change, and practical consideration enable it.

Management also proposes to change the way in which generation costs are allocated.[20] They advocate retention of the peak-and-average approach to splitting costs between demand and energy causation but have changed the peak portion of the allocation process. The peak-and-average process is one of the many generation classification methods that are well established.[21] Previously, Management used the 4CP allocator to allocate demand-related costs, but has concluded that system peaks do not reveal when generation capacity-related costs currently peak, which is during evening periods when system reserves are at their lowest. As a result, they have chosen to adopt a method that uses loss of load probability (LOLP) weighted allocator as an indicator of demand-related cost. This is a realistic response to the development of solar generation capability during the daytime and its natural disappearance as evening advances, with attendant changes in system reserve conditions. LOLP is a long-established measure of reserve conditions and is an appropriate device for measuring capacity cost incidence over time, and thus allocation of generation capacity cost. This allocator is also applicable to the demand portion of FPPAM for the same reasons.

With respect to its allocation of ancillary services, Management has retained its existing approach, namely to treat Ancillary Services 1 and 2 as demand-related and the remainder as energy-related.[22] This approach is sensible by industry standards and Management's allocators of demand (4CP) and energy (kWh delivered) are not controversial.

2.3.2.2 Transmission

Management continues to use the 4CP allocator for transmission service cost allocation. The change to demand-related allocation for generation services might cause one to inquire about this allocator as well. However, as the CAS report makes clear, the 4CP allocator is retained to reflect the fact that costs of the transmission system continue to be related to the system's peak usage, while the demand-related generation costs are instead now related more closely to reserve conditions as reflected in LOLP. The retention of the 4CP allocator for transmission appears reasonable.

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[20] SRP, *Cost Allocation Study in Support of Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle*, December 2, 2024, pp. 1-2.

[21] See the *NARUC COS Manual*, p. 57.

[22] It is somewhat arbitrary to include ancillary services within the generation function, since these services provide means of managing load in the transmission system. However, generators take a leading role in providing these services.

2.3.2.3 Distribution

The distribution function covers Dedicated Distribution, Distribution Facilities and Distribution Delivery categories, each with its own cost classification and allocation. Dedicated Distribution is simply the category of direct assignment of distribution costs to customers or customer classes. No allocator applies in this case due to direct assignment of all costs.

Distribution Facilities contains customer-related costs, i.e., costs that do not vary within a class regardless of customer size, but that may vary between classes due to differences in equipment needed to serve them. This challenge usually requires a weighted customer allocator of some sort that counts the number of customers per class but adjusts the count to recognize how costs differ across class. Management uses a variant of the NCP allocator, "sum of NCP", normally used for demand-related costs, as a weighting device.[23] The approach also recognizes differences within the residential classes as an additional weighting factor. This method of weighting is somewhat unusual in that it does not conform strictly to the cost-weighted customer count method used elsewhere, but it appears sensible, nonetheless.

The Distribution Delivery category, which groups demand-related distribution costs, uses an NCP allocator, which is conventional.

It should also be noted that Management's CAS is careful to "levelize" distribution costs. The approach explicitly identifies costs by voltage service level (VSL) and, for example, excuses transmission and primary VSL customers from secondary costs. This is standard cost allocation practice and Management's approach is sound.

2.3.2.4 Customer Service

The Customer Service function includes Billing and Customer Service, Meters, and System Benefits categories of functional classification. Regarding Billing and Customer Service, Management makes use of a Customer Systems Study which provides cost estimates by rate class. Similarly, Metering costs serve as the basis for allocation of the Meters category. Typically, this allocator is derived by using a customer count and weighting by cost per meter, and cost per meter reading event. SRP derives its allocator from Marginal Cost Study results, which references appropriate metering project data.

Management's approach is unusual in that it conducts a subsequent reallocation of costs via "smoothing" of residential costs across all residential customers, and of commercial costs across all commercial customers.[24] This action occurs, according to the CAS, as a result of an agreement to which Management assented as part of the 2019 price process. The approach is unusual because it constitutes a departure from cost causation, and more properly belongs in the rate design process.

However, from a practical perspective, it is not important where the calculations to smooth take place as long as the utility retains an understanding of cost to serve. Management does this by passing forward the unsmoothed values in its calculation of class target revenues and, hence

[23] SRP, *Cost Allocation Study in Support of Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle*, December 2, 2024, P. 38.
[24] SRP, *Cost Allocation Study in Support of Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle*, December 2, 2024, pp. 37, 47.

class rate of return. Parenthetically, it should be noted that many utilities unavoidably engage in smoothing on occasion simply because their data in certain categories lack the class detail necessary to differentiate those costs by class. SRP's CAS has sufficient detail to differentiate metering costs by type of customer within the major categories. Consequently, the variance from normal practice is one of where cost spreading or averaging occurs, the cost allocation model instead of rate design calculations. Ideally, then, Management should not smooth costs within the CAS, but in practice, their approach causes no loss of information for costing and pricing purposes.

System Benefits, as mentioned, are loosely associated with Customer Service. The category records costs resulting from expenditures that confer benefits upon customers based on their overall energy consumption. Management's approach is sensible and transparent, given the presence of a separate schedule with System Benefit Charge (SBC) calculations.

<u>CA Energy Consulting Assessment:</u>

- Management's cost allocation proposal is closely related to its previous plan for most allocators. Its allocator modifications appear to be a response to changing conditions and the creation of new functional classifications in generation (FPPAM split) and, secondarily, to the availability of new information to facilitate the segmentation of distribution costs into Delivery and Facilities.

- Management's smoothing of metering costs properly belongs in rate design, but the data necessary to smooth reside in the CAS model. It is practical to retain it there, given the requirement to conduct smoothing. Management has ensured transparency by conducting its target revenue and rate of return calculation based on costs calculated without smoothing.

2.3.3 Allocation of Net Plant

Management receives plant valuation data on a net basis only, and functionally classified outside the CAS model. Additionally, the utility adjusts net plant for construction work in progress (CWIP) a conventional adjustment. The model allocates net plant to class in a straightforward manner, using the same allocators for each functional classification's assets that it uses for its expenses. This is in line with industry practice. Changes to classifications and allocators will have caused changes in the shares of net plant allocated to class, but it is preferable to apply changes to allocators to both expense and net plant accounts to avoid skewing target revenue and rate of return estimates.

<u>CA Energy Consulting Assessment:</u>

- Management's approach is consistent with its allocation of operating costs and is not controversial.

2.4 Development of Revenue Requirements

Having functionalized, classified, and allocated costs and net plant, the CAS proceeds to develop revenue requirements by class and in aggregate. As with most utilities, SRP computes retail electric revenue by class at current rates and at proposed rates, the difference yielding a revenue increase by class and other summary information. Revenue at proposed rates yields revenue requirement to cover costs.

Management's CAS assembles current rate-based revenue via the process of calculating revenue by class as the sum of operating and other costs according to FY 2026 of the 2025 Financial Plan, and then adjusting it for test year differences from the plan, including contributions to future capital and transmission revenue, among other adjustments. (See Schedule 2 of the CAS model.)

Management's estimate of revenue requirements at proposed rates is derived from FY 2026 data, subjected to the same cost allocation rules as current expenses. Management adjusts the revenue requirements as developed in the plan to reflect requirements of gradualism in rate changes. As the CAS states, "…Management's proposal balances the Equity, Cost-Relation, and Gradualism Pricing Principles, resulting in the proposed revenue for some pricing components differing from estimated costs."[25] The result is revenue requirements by class sufficient to cover costs.

As with the smoothing steps undertaken with respect to metering, the preferred location for adjustments to revenue requirements for the above reasons is in a rate design model. However, practical considerations suggest that the CAS model is a useful place to make such computations due to data availability. SRP's approach is to compute requirements for rates in one location (Schedule 9) and separately to compute returns using the unadjusted costs (at the bottom of Schedule 10). This approach provides rate designers with target revenues in one location and returns in another. This latter information enables Management to produce standard measures of revenue recovery for each class.

<u>CA Energy Consulting Assessment:</u>

- Management's computation of revenue requirements results in full coverage of costs at proposed rates.

- The development of revenue requirements at proposed rates incorporates adjustments to class revenue requirements that reflect rate design-related considerations. This approach is computationally sensible. The approach also uses unadjusted costs to facilitate estimates of return by class.

2.5 Summary

Management's CAS and its associated model properly and clearly perform the task of allocating the components of proposed revenue requirements to rate class. Functional classification categorizes costs realistically by cost causative factor and the allocators used for each factor are sensible from the perspective of theory and industry practice.

Management has chosen to modify its classification and allocation methods in ways that clarify cost relationships and improve cost allocation. Splitting FPPAM costs into demand- and energy-related components recognizes the increase in demand-related charges in purchased power. Similarly, the updated method of splitting (non-assigned) distribution costs into demand- and

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[25] SRP, *Cost Allocation Study in Support of Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle*, December 2, 2024, p. 68.

customer-related components based on improved information appears to improve the allocation of these costs.

The CAS model provides revenue requirement information that meets two purposes. First, the model provides revenue/cost relationships by class that accurately represent rate of return by class. Second, the model provides cross-class adjustments to revenue requirements necessary to meet the gradualism and related rate design objectives of the utility. While other utilities typically conduct this second function in separate rate design models, SRP capitalizes on data availability in the CAS model to make these preliminary rate design computations. This constitutes an acceptable departure from traditional cost-of-service model practice, because the model produces unadjusted rate of return information as well.

A final comment pertains to the CAS model itself. It is orderly in its development of costs and clear in the various steps necessary to arrive at a fully allocated set of costs. This clarity helps to establish the veracity of the computations.

3. MARGINAL COST STUDY

3.1 Introduction to Marginal Cost

Marginal cost is the change in total cost with respect to a change in the level of output, where output refers to the production and delivery of goods and services. Marginal costs are specific to industry and technology, and the goods and services that are produced. Vertically integrated electric utilities provide retail consumers with bundled electricity services that include:

- generation services in the form of energy and reserves;
- transmission and distribution services (wires services) which provide for the transport of power between locations where it is produced (generators) and locations where it is consumed (customer sites); and,
- interconnection services involving the physical connection of customers to distribution (and transmission) networks.

The importance of marginal costs stem from economic theory regarding efficient pricing. That is, in a competitive market, social welfare is maximized when prices are equal to marginal costs. At this point, the marginal value to the customer (the price that they are willing to pay) equals the marginal cost of providing the good or service.[26] Therefore, marginal costs play an important role because they can inform how regulated utilities, as government sanctioned monopolies, can operate to mimic a competitively efficient market environment. Marginal costs can be used to inform retail pricing of services under a variety of rate designs (e.g., time-of-use, economic development rate, standby tariff, real-time pricing, etc.), allocate revenue requirement, and determine value of energy reduction programs (e.g., demand response, energy efficiency, distributed energy resources). SRP uses marginal costs to inform rate design. For example, the marginal cost of energy is used to calculate rate differentials between time-of-use (TOU) periods.

[26] This equality assumes that the market for the good is workably competitive, i.e., that no provider or buyer can exert influence on the price.

3.2 Overview of SRP's Marginal Cost Study

SRP, as a vertically integrated utility, owns generation, transmission, and distribution facilities. Their Marginal Cost Study (MCS), therefore, estimates the marginal cost for each of these functions in providing electricity services.

The marginal costs of generation are load-related costs that can be classified as either energy- ($/kWh) or demand- ($/kW) related. Marginal energy costs of generation refer to the incremental fuel costs and, where relevant, variable operating and maintenance costs associated with a change in load level. Marginal demand-related costs, or capacity costs, of generation serve as a proxy for reliability costs which reflect the costs associated with unexpected power interruptions (i.e., the likelihood and magnitude of electricity demand not served because of power outages). Capacity costs of generation determine reliability costs according to incremental costs of generating capacity, under the assumption that, in equilibrium, the cost of capacity equals the value to customers of reliability.

SRP's wires services are provided by meshed and, to a lesser extent, radial network transmission and distribution facilities. The marginal costs of wires services include both load- and nonload-related dimensions. In essence, wires costs are jointly determined by peak loads (load-related) and consumer locations and transport distances (nonload-related).

Interconnection services include voltage transformation, metering, and connection via service drops. Interconnection services cover the capital, installation, and maintenance costs of electrical equipment, which are typically recorded within the capital accounts of power delivery. The incremental costs of interconnection services include load- and nonload-related (customer) costs associated with the connection of retail consumers to SRP's distribution facilities. Interconnection services also include billing and customer services.

SRP's MCS estimates the marginal costs for generation, wires services (transmission and distribution), and interconnection services. The marginal costs are separated into energy, demand, and customer-related charges based on cost causation, and averaged over each rate class's relevant season (Summer Peak, Summer, Winter) and TOU period (On-Peak, Shoulder-Peak, Off-Peak, Super Off-Peak), where applicable. We compartmentalize our review below based on the marginal costs that feed into the energy, demand, and customer summaries.

3.2.1 Energy-Related Costs

Energy-related marginal costs exist for the functions of generation, transmission, and distribution. Marginal energy costs of generation reflect the production cost for the incremental unit of electricity. Marginal energy costs of transmission and distribution are reflected as line losses on the system.

SRP participates in the Western Energy Imbalance Market (WEIM) and therefore estimates the marginal energy costs of generation using market-based opportunity costs. This approach sets marginal energy cost according to the expected electricity prices, as estimated for wholesale electricity markets over forward periods. Generally speaking, electricity prices so determined are the result of competitive auction procedures and reflect the highest-valued use of the participating generator units for the market as a whole. Properly designed, auctions simultaneously obtain least-cost short-run supply and set prices equal to the marginal cost of supply, including energy and operating reserves. In brief, in the presence of competitive wholesale markets, the prices obtained reflect opportunity costs, the highest-valued use of marginal resources. Such a result is fully consistent with least cost dispatch.

SRP's marginal energy costs of generation are based on forward market prices, shaped based on CAISO's historical market prices.[27] The hourly prices are averaged over each rate's respective season and TOU periods, where applicable.[28] Finally, line losses for transmission and distribution are included in order to calculate the total marginal energy cost.

CA Energy Consulting Assessment:

- The marginal energy costs of generation are based on market clearing prices from the WEIM energy market. This approach is appropriate because these prices reflect market-based opportunity costs.
- The marginal energy cost of transmission and distribution are appropriately based on line loss studies.

3.2.2 Demand-Related Costs

SRP employs a planning-based approach to estimate capacity- or demand-related marginal costs. The process of this approach can be summarized by the following steps:

- Calculate the $/kW cost of investments based on historical or future capital projects deemed necessary to meet load growth (and potentially reliability).
- Annualize investment cost using an economic carrying charge (ECC). The ECC can incorporate elements attributable to the capital investment, such as return on capital, depreciation expense, and property tax. The ECC also accounts for life of the capital and inflation.
- Calculate the all-in cost of investment by including adders for costs on the margin, including general plant, operations and maintenance (O&M), and administrative and general (A&G). These costs can also include adjustments for reserve margins, line losses, and working capital.
- Attribute the all-in investment costs to hours of the year using techniques that reflect cost causation, such as loss of load of load probability (LOLP) or probability of peak (POP) analyses, where applicable.

SRP estimates demand-related marginal costs for generation and transmission, distribution substations, and distribution delivery (i.e., getaway costs and primary feeders). As mentioned above, the first step calculates the total investment cost for each of these functions and then divides the total investment cost by load capacity to calculate a $/kW amount. The total investment cost calculation is based on the following for each function:

- Generation: weighted average of aeroderivative & frame combustion turbines.[29]

[27] Forecasted values are calculated using adjustments for inflation.

[28] The hourly prices are averaged over forecasted years 2026 through 2028.

[29] Aeroderivative engines are derived from aviation designs. Frame combustion turbines are larger designs designed for stationary use.

- Transmission: historical investment in growth-related transmission projects for Fiscal Year (FY) 2019 through FY 2024, adjusted for Contribution in Aid of Construction (CIAC) and inflation.[30]
- Substations: historical investment in growth-related substation projects for FY 2019 through FY 2024, adjusted for CIAC, inflation, and getaway costs per substation.[31]
- Distribution delivery: includes getaway costs and primary feeders. These marginal costs are estimated on a $/transformer kVA basis. Annual costs between 2020-2025 are averaged by different segments of customer and voltage service level.[32]

Marginal capacity cost is the annual fixed charges related to the installation of capacity. SRP annualizes the total investment cost per kW using an ECC and loading factors for general plant, O&M, A&G, and working capital expenses related to the investment.[33] SRP's general formula to calculate annual marginal capacity costs for each function is:

$$MCC = IC \times (1 + GeneralPlant) \times (ECC + A\&G_{Plant}) + O\&M \times (1 + A\&G_{O\&M}) + WorkingCapital.$$

The variable *IC* represents the investment costs stated as $/kW. The variable *GeneralPlant*, $A\&G_{Plant}$, $A\&G_{O\&M}$, indicate loading factors for general plant-related costs, A&G costs related to general plant, and A&G costs related to O&M expenses, respectively.[34] The variables *ECC* represent the ECC rate. Finally, the variable *WorkingCapital* represents total working capital and includes loading factors for materials and supply, cash working capital for O&M, and prepayments, with multiplying factor weighted average cost of capital (*WACC*).[35] The marginal capacity cost is estimated separately for generation, transmission, and distribution substations

[30] The load growth is represented by actual and forecasted loads between FY 2020 and FY 2028 since capital investment is designed to serve following year's load growth.

[31] The load growth is represented by actual and forecasted loads between FY 2020 and FY 2025 since capital investment is designed to serve following year's load growth.

[32] The customer segments are residential and general service. For residential, the voltage service level segments are multi-family, single family <=200A, single family >200A. For general service, the voltage service level segments are 0-200A single phase (1PH), 201-800A 1PH, 0-800A 3-phase (3PH), 801-2000A 3PH, 2001-4000A 3PH, >4000A 3PH. The distribution facilities category includes customer service drops; however, customer-voltage level segments do not differentiate between overhead and underground service drops.

[33] Estimates for marginal costs of capital using a carrying charge approach should assume a so-called all-in perspective, including an economic carrying charge rate on the incremental investment in capital and operating and maintenance expenses. Capital includes facilities, general plant, materials and supplies, working capital, and possibly fuel inventory. Operating and maintenance expenses include direct O&M, property, and other taxes such as labor taxes, labor-related benefits, insurance, and administrative and general overhead expenses.

[34] SRP calculates the general plant loading factor using a regression that estimates the cumulative general plant additions between 1998 and 2024 as a function of the cumulative additions to total electric plant (excluding general plant). SRP calculates O&M expenses as the average between FY 2020 and FY 2024, after adjusting values by a labor cost index.

[35] $WorkingCapital = \{IC \times (1 + GeneralPlant) \times (MS + Prepayments) + O\&M \times (1 + A\&G_{O\&M}) \times CashWorkingCapital\} \times WACC.$ Where variables *MS*, *Prepayments*, *CashWorkingCapital* each represent materials & supplies, prepayments, and cash working capital for O&M expenses, respectively. Finally, the variable *WACC* represents the weighted average cost of capital and is used to determine the revenue requirement associated with working capital.

using the generic formula. Values differ with respect to the investment costs, ECC, and O&M expenses whereas values for loading factors are the same.

The calculation of the marginal capacity cost for generation includes additional adjustments for the Effective Forced Outage Rate (EFOR) and a Peaker Proxy. The EFOR adjustment effectively scales the calculated marginal capacity cost of generation upwards to account for the likelihood that the marginal generator will be unavailable for service during peak periods, resulting in additional capacity needed to supply the incremental kW. The Peaker Proxy adjustment effectively scales the marginal capacity cost of generation downward to reflect the current supply-demand balance being supply long.[36]

The ECC refers to the annual all-in carrying charges on capital including depreciation, payback of principal, interest charges, property tax, corporate income taxes (where appropriate), and return on capital.[37] The derived general form of SRP's ECC rate is equal to:

$$ECC = \left(\frac{NPV\_Rev\_Requirement + \ NPV\_Dispersed\_Retirements}{Initial\_Investment\_Cost}\right)\left(\frac{(DR - Inf\ )\ (1 + DR)^{t}}{(1 + DR)^{N} - (1 + Inf)^{N}}\right),$$

where *NPV_Rev_Requirement* is the net present value of the revenue requirement stream associated with the investment, *NPV_Dispersed_Retirements* is the net present value of replacing dispersed capital retirements related to the initial investment*, Initial_Investment_Cost* is the original investment value, *DR* is the discount rate, *Inf* represents inflation net of technological progress, *t* indicates the time period of the ECC calculation,[38] and *N* indicates life of the capital investment.

The first term, the ratio of the net present value of the revenue requirement and the initial investment cost, provides a *revenue requirement present worth factor*. SRP's MCS revenue requirement includes costs for property tax, depreciation, return to stockholders and bondholders, and replacement value for dispersed capital retirements. The stream of revenue requirements is discounted using a company's weighted average cost of capital (WACC) to calculate the net present value.

The second term represents, conceptually, the replacement and deferral value of the investment. As stated above, the ECC is calculated separately for generation, transmission, and distribution substations. SRP's ECC calculation varies between capital investment type largely because of differences in the input parameters for the life of the capital, inflation net of technical progress, and Iowa curve assumption for early retirements.

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[36] The Peaker Proxy adjustment uses the planning reserve margin as a proxy for the ratio of expected Loss of Load Hours (LOLH) to expected LOLH.

[37] The ECC is a mathematical expression which is obtained through a conceptual simulation of the financial impact of a change in the future path of capacity and investment, such as generating capacity, in response to a change in expected resource demands in the future, representable as peak loads. An underlying assumption of the ECC methodology is successive replacement of equipment following the full depletion of capital. The ECC expression yields a series of annual ECC rates, stated as a percentage of investment, that cover the total financial charges on investment for capacity over the life of that capacity. While the ECC approach covers financial costs over the life of capital stated in discounted terms, the ECC rate for any one year is often sharply different (either higher or lower) from the annual financial cost rate, as determined on a basis of financial accounting. For SRP's study, the capital carrying cost—i.e., the ECC rate expressed as an annual percentage—is for the first year following investment.

[38] This is set to zero since the ECC is calculated for the initial period.

The annual all-in marginal capacity costs of generation, transmission, and distribution substations are allocated to hours over the year based on the likelihood of the system peaking and needing the relevant resource. Specifically, the marginal capacity cost for generation is allocated based on the Loss of Load Probability (LOLP) whereas marginal capacity costs for transmission and distribution substations are allocated based on their respective probability of peak analyses. Hourly marginal costs of capacity for generation, transmission, and distribution substations are aggregated to calculate a total hourly marginal cost of capacity. Distribution delivery demand-related costs are allocated evenly throughout the year.

Like energy-related costs, hourly demand-related (or capacity) marginal costs are averaged over each rate's respective season and TOU periods, where applicable. Finally, line losses for transmission and distribution are included in order to calculate the total marginal energy cost.

<u>CA Energy Consulting Assessment:</u>

- Demand-related marginal costs of generation are based on the all-in cost of combustion turbine (CT) generators used to meet peak demand. SRP's MCS also included estimates using solar generation with 4-hour battery storage as the marginal generating unit used to meet peak demand. We recommend that SRP continue to compare the capacity costs of these two peaking generating units. SRP's decision to use the CT generator as the unit on the margin is reasonable. However, using the solar plus battery generating unit may become more appropriate in the future if it becomes the unit on the margin.
- Demand-related marginal costs for transmission and distribution substations are based on historical investments used to meet load growth. This approach is common when a utility does not have sufficient future capital projects on which to base marginal cost estimates. In some instances, a mix of future and historical projects can be used to calculate marginal costs. We recommend that in the future SRP consider incorporating future cost estimates where possible to improve alignment with the principles of marginal costs as a forward-looking concept.
- SRP uses an ECC approach to annualize demand-related marginal costs. We agree with this approach, the ancillary costs included (e.g., O&M, A&G, general plant, and working capital) and SRP's execution of the method.
    - Within the calculation of the ECC rate, SRP includes replacement value for dispersed capital retirements. We have seen this included previously in marginal cost studies. However, it is our experience that this is an uncommon addition. SRP should feel free to continue its use, especially since it is not very material.

3.2.3 Customer-Related Costs

SRP's MCS calculates customer-related marginal costs for distribution facilities (i.e., secondary feeders, transformers, and service drops), meter, billing, and customer service. Customer-related marginal costs are stated as $/customer for an annual or monthly period.

Distribution facilities costs, like distribution delivery costs above, are based on average costs between 2020-2025 for different segments of customer and voltage service level.[39] Meters

[39] The customer segments are residential and general service. For the residential class, the voltage service level segments are multi-family, single family <=200A, single family >200A. For general service, the

include the actual installed cost of the meters or devices used to measure electricity. SRP's MCS calculates a monthly cost per meter for each customer class. Like demand-related costs, the all-in investment cost for distribution facilities and meters includes various types of ancillary costs, such expenses for general plant, A&G, O&M, and working capital. Therefore, the calculation for distribution facilities and meter expenses is equivalent to the approach described above, which calculates an all-in investment cost and then annualizes the cost using an ECC approach. The result is a total annual (or monthly) distribution facilities and meter cost per customer, by customer class.

SRP provided annual billing and customer service expenses per customer per rate class.[40] The utility's MCS aggregates monthly customer service and billing-related expenses with meter-related expenses to calculate a total customer-related marginal cost by month and rate class.[41]

CA Energy Consulting Assessment:

- Customer-related marginal costs include meter, billing, and customer services. These costs appear to be handled correctly. For instance, meters are a capital expense that, similar to demand-related costs, are annualized using an ECC approach. SRP's current approach is appropriate.

3.2.4 Application of Marginal Costs to Rate Design

SRP uses marginal costs as an input to rate design decisions. SRP states that marginal costs have been used in three major ways: 1) the hourly time patterns of marginal costs and their changes over time have helped determine and modify TOU periods, 2) the price differential between TOU periods is based on differential in marginal energy costs, and 3) marginal costs have helped rate designers to make energy prices more efficient for specific rates by providing guidance in determining price levels.

CA Energy Consulting Assessment:

- SRP appears to use marginal cost to determine the time periods of its TOU rates. This rate application includes modification of TOU time periods to reflect a change in the pattern of marginal costs. This is an appropriate approach to TOU time period determination.
- SRP uses marginal costs to inform the price differential between TOU periods for many of its rates. We agree with this use of marginal costs.

3.3 Summary

Management's approach to developing marginal costs appears to conform to economic theory and to be in line with industry practice. In particular, the approach to generation marginal costing takes advantage of available wholesale market information in estimating marginal

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voltage service level segments are 0-200A single phase (1PH), 201-800A 1PH, 0-800A 3-phase (3PH), 801-2000A 3PH, 2001-4000A 3PH, >4000A 3PH. The distribution facilities category includes customer service drops. However, customer-voltage level segments do not differentiate between overhead and underground service drops.

[40] SRP's marginal cost model indicates that these expenses are for FY 2026.

[41] Options are included for rate classes that have multiple meters installed.

energy-related costs of generation and in developing marginal capacity costs. Energy-related costs are tied to energy markets and capacity costs are based on SRP's estimates of capacity cost of units likely to be at the margin: conventional combustion turbines along with renewable resources and battery storage.

Costs of transmission and distribution recognize line losses in marginal energy costs and historical costs of growth-based investment in delivery capability. The use of the economic carrying charge approach to developing annualized capacity costs is well established and lends credibility to these cost estimates.

Customer-related marginal costs rely on customer service and billing data, as is appropriate. This approach also appears sensible.

Management's use of marginal costing information in pricing is in line with industry practice as well. The traditional constraint of meeting revenue requirements results in the use of embedded costs in setting price levels, but marginal cost patterns offer guidance in the determination of TOU pricing periods, the setting of price ratios between periods, and the occasional use of marginal prices where revenue recovery is not at risk. This occurs in dynamic pricing programs where price offers arrive at short notice for consumption increases (when energy is ample and inexpensive) or decreases (when system reserves are low).

4. RATE DESIGN PROPOSALS

4.1 Overview of SRP's Price Proposals

Management presents its price proposals in *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle*, dated December 2, 2024. This document summarizes Management's general plans, sets out specific changes to rate structures, and systematically lists rate structure, current and proposed prices and the estimated distribution of bill impacts for the participating customer population.

The salient features of the pricing changes involve 1) rebalancing of revenue recovery in order to reduce rate of return variability across customer classes, 2) an increase in customer charges, relative to other prices, in some rates, to improve the match between fixed costs and fixed charge cost recovery, and 3) the modification of time-of-use (TOU) time periods in several cases to improve the match between the price pattern of retail rates and the pattern of generation cost prices as reflected in wholesale markets and in SRP's valuation of capacity. Each of these changes represents a significant change in the direction of improving the equity of cost recovery and the efficiency of prices, that is, their ability to reflect the cost to the utility of providing the power consumed by the customers.

Rebalancing revenue recovery by setting prices so that rates move in the direction of "rate parity" is a recognized objective in most rate applications. Rates typically do not get set to achieve rate parity exactly because this often would impose more significant rate changes than customers can readily tolerate. Especially at times when cost allocation methods change, rebalancing should recognize the need for gradualism.

Management's plan appears to achieve this objective. Figure 5 of the *Proposed Adjustments* document depicts the current and proposed return by customer class. All returns increase, in line with the aggregate, but the two Residential class returns increase by slightly more than that of the General Service. Large General Service's return increases by slightly more than the aggregate. The largest increase occurs for the Residential Solar class, which is sensible given that its return was the lowest of all.

Increasing customer charges is a common theme in rate applications currently. Two influences motivate this change. First, utilities are often guided in price setting by the unit costs that emerge from the CAS. Unit costs are often developed for customer-related, demand-related, and energy-related costs by class for this purpose. Proximity of customer charges to customer-related unit costs results in these fixed costs being covered by a fixed charge, a useful general principle. Second, the emergence of customer-site generation served typically by net metering tariffs has exposed utilities to revenue attrition as sales to customers drop. With volumetric pricing covering a significant portion of fixed costs, full fixed cost recovery is endangered by the reduction in consumption.

Some may regard the increase in customer charges as cause for concern, since small customers will tend to have larger bill increase percentages than larger customers. The change is compatible with equity considerations, since it reduces the historical cross subsidy of small customers by larger ones. Additionally, the energy price is reduced as an offset to the rise in customer charges, which tends to improve the price signal to customers, especially those with distributed generation (DG), since their bill reductions are likely to be a better match to the actual cost reductions of the utility. Management's move to increase fixed cost recovery through fixed charges is thus in line with industry practice and with embedded cost-based pricing generally.

Management's changes to customer charges are a mix of attempts to better reflect cost and to simplify charges within the major classes. The CAS includes documentation of smoothing customer-related costs within the Residential and General Service classes that reflects the utility's objective of equitable treatment of customers. Additionally, Management has modified its pricing strategy by introducing tiered pricing to reflect differences in customer-related costs related to customer size, complicating pricing but achieving a better match to customer cost.

Management's proposed shift in TOU peak and off-peak hours, and the introduction of super off-peak periods is combined with the freezing and planned eventual closure of several TOU rates. This constitutes significant rate structure change, but it meets SRP's rate and pricing objectives since it is gradual and is designed to improve the reflection of cost in rates. As noted in Management's document, the current designs now induce customers to shift load out of hours that are now relatively low-cost while not yet recognizing that the new generation services price peak is in the evening. Introducing new rates with the new TOU price pattern that reflects the new generation services cost pattern offers customers a new path to lower cost service while respecting the principle of gradualism by proposing that the frozen existing rates be closed by November 2029.[42]

Another feature of Management's pricing methodology is the role played by marginal generation costs. The revision in time periods is based on the change in marginal costs, certainly.

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[42] SRP, *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle*, dated December 2, 2024, p. 37.

Additionally, though, Management has made changes to the seasonal pattern of prices to reflect changes in the seasonal pattern of marginal costs, and changes in on-peak/shoulder/off-peak price ratios of TOU rates within seasons has been similarly influenced. Marginal costs do not determine price levels, since these are controlled by revenue requirements, but the resulting price pattern moves prices across most rates in the direction of price efficiency, i.e., prices that signal the cost of additional energy consumption, a key to indicating the value of a resource to customers for decision making purposes.

Management also proposes to extend the TOU pricing principle to the FPPAM price. This is a useful step forward. As with other utilities, a significant but flat fuel and purchased power adjustor, when combined with TOU pricing acts to reduce the on-peak/off-peak price differential, weakening the signal to customers that shifting load will reduce their bills and reduce system costs at the same time. Introducing TOU pricing to the FPPAM reduces this price dilution and helps the utility's prices to match costs. The move also improves equity, as it allocates more cost to customers whose loads are peak coincident and reduces costs allocated to the less peak coincident customers.

Management also proposes to increase the deadband range for FPPAM adjustment, to reflect the increase in size of dollar flows, and therefore absolute dollar variability in the account. Utilities have a broad range of preferences on this issue, with some preferring frequent adjustments that are hopefully smaller than less frequent and usually larger adjustments. SRP has discretion in how to proceed.

Another notable modification pertains to the Transmission Cost Adjustment (TCA). The TCA is currently valued at zero in rates and in the CAS, but Management states that SRP expects to see considerable potential variability between price processes for an increasingly important cost item. The increase in significance arises from SRP's increasing engagement with the California Independent System Operator and the Southwest Power Pool. The costs and benefits of this engagement are likely to be large and variable, and therefore merit consideration similar to the utility's approach to fuel and purchased power. Management proposes to make the TCA reflect the pricing of transmission in their Open Access Transmission Tariff, with the result that TCA prices are expected to change in response to OATT price changes that occur between price processes. Thus, changing the value of the TCA in step with the OATT would keep the retail share of transmission revenue recovery in line with the utility's costs. The Board of Directors of SRP will have the authority approve such changes as the need arises.

This plan appears to meet the requirements of an adjustor: large and variable costs not within the control of the utility (transmission prices in this case, if not peak demands). Management's proposal for the TCA seems sound and in line with its rate principles of cost coverage and fairness.

It should also be noted that Management's presentation of information is well organized and detailed. In addition to a general description of the proposed changes, information for each tariff includes an overview, key facts, a description of the proposed changes including overall impact, existing and future tariff prices with component detail, pricing seasons and time periods, and bill impacts, including a histogram of impacts and breakout by consumption stratum.

CA Energy Consulting Assessment:

- Management's general themes of rate revision appear to match well with the utility's objectives in that they improve costing accuracy and equity across customers, and enhance price efficiency, the ability of prices to communicate incremental costs to customers of changes in their behavior.
- Management's organized presentation of rate detail permits informed inquiry into the proposed changes and their impacts. This is an excellent template for future price processes.

4.2 Residential Rates

Management's proposal involves substantial revisions to the Residential rates portfolio in the long term. Applying the principle of gradualism, customers will be able to move to new rates over a four-year period (by November 2029). As mentioned above, the monthly customer charge will be harmonized across rates and a tiered structure established to differentiate cost by type of housing unit. TOU pricing periods will change as customers move from the existing frozen rates to the new offerings. The current rates feature daytime peak periods while the new rates have evening peaks, reflecting the shift in peak periods as defined by market price of generation services.

The E-23 rate, which serves about half of customers, will remain stable aside from the customer charge changes and the removal of an inclining block structure that produces a small difference in energy price at the 2000 kWh per month boundary. (Current energy price rises from $0.1358/kWh to $0.1471/kWh in the summer peak months.) The seasonal nature of the energy price will remain. The overall bill impact is an average increase of 3.5%, with an estimate of about 13% of customers experiencing bill increases of greater than 10%.[43] Bill increases are greater for smaller customers because of the customer charge increase, which acts to reduce the under-collection of fixed costs via a fixed charge. In brief, bills rise the most for customers who, within the class, had the lowest degree of cost coverage.

As revised, the E-23 rate will become a seasonal flat energy price rate with an increased customer charge on average, due to the tiered pricing effect. The rate change appears to make the allocation of costs within the rate fairer while retaining rate and revenue stability.

The rates serving distributed generation customers (E-13, 14, 15, and 27) feature a reduction in customer charge since their current customer charges are higher than those of other rates. This outcome is a result of the policy of smoothing of the charge across rates. The rate structures remain stable, with the current TOU periods continuing. Overall increases for these rates are 5.9%, higher than those of the standard tariffs, reducing the degree of subsidy currently enjoyed by this class. Still, small shares of customers have bill increases in excess of 10%.

The revised DG tariffs improve revenue recovery from customers from whom revenues have been under-recovered in the past. However, the energy prices continue to be high in the energy-only rates E-13 and 14, suggesting that SRP continues to have exposure to under-recovery.

[43] The percentage is actually the rate increase percentage for rates E-23 and 24 (the M-Power prepayment rate). These rates' charges are being equalized. The estimate is derived from calculations in which about 47,000 customers in a sample of 357,000 had bill increases greater than 10%. The sample consists of a group of customers with twelve months of complete, clean data. The class population is about 540,000.

(Rates E-15 and 27 have a demand charge and are not as susceptible to subsidy in consequence.) These rates are all to be frozen, according to the price plan, with customers being eligible for new rates. (Customers will be able to choose their new rates, with the default new rates being set out in Table 6 of the *Proposed Adjustments* document. Rate E-16 is a new seasonal TOU and demand tariff and Rate E-28 is currently a pilot with the current TOU periods which is proposed to be converted to a permanent rate with the new TOU periods including a super off-peak period.)

Management's proposal offers price and rate structure stability, with ample time to allow customers to choose a new rate design. The closure of energy-only Rates E-13 and 14 is desirable for reduction of cross subsidy, but there may be some residual exposure with Rate 28 due to the absence of a demand charge and the continuation of a net billing structure with export pricing.[44]

The remaining current rates offer Residential customers various forms of seasonal TOU service for standard end-use customers and those with electric vehicle charging needs. Most of these are to be frozen, according to the plan, the exception being the MPower prepay rate design (E-24). Customers will be able to choose a rate design through late 2029, with the default being E-23, the flat seasonal design.[45] Rates E-16 and 28, though, will be available for continued TOU service.

For these rates, customer charge increases are more noticeable, especially for Tier 3 which reaches $40. Nevertheless, the overall bill increases are modest, in the range of 2.7 to 3.7%[46], with relatively small shares of customers having bill increases of more than 10%.

Management's focus for these rates appears to be on customer charge adjustment in the short term and TOU period optimization in the long term, combined with modest increases in rate of return. This strategy appears sensible in that it is gradual in terms of structural correction to reflect changing time periods and in bill impacts on customers.

The MPower rate (E-24) will be harmonized with the E-23 rate. Management states that the customer-related cost differential that used to result in a premium for E-24 has been reduced with the advent of interval metering for all customers, which suggests that there is a cost basis for the smoothing undertaken by the price plan.

The two new rates, E-16 and E-28, appear designed to offer current TOU and demand service customers, including DG and EV charging customers useful alternatives to the ongoing flat seasonal rate E-23.[47] These rates offer the new TOU pricing periods to customers at the effective

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[44] Net billing is based on two-channel metering that records net inflows to the customer site in one channel when the customer is consuming more than it is producing, and net outflows to the grid from the customer site in the other channel when the customer is producing more than it is consuming. The utility bills total inflows at the standard energy price and outflows to the grid at avoided cost. This design incurs some degree of revenue shortfall because the standard tariff energy price includes some fixed cost recovery. When the customer has net inflows to the site and site production is non-zero, some fixed cost recovery is foregone.

[45] All customers, according to the proposal, must be on new service by the November 2029 billing cycle.

[46] SRP, *Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the November 2025 Billing Cycle*, dated December 2, 2024, Table 4.

[47] Distributed Generation customers will not be able to take service under the E-23 rate, as this would result in revenue attrition and eroded fixed cost recovery.

date of rate approval and will be available as customers make the transition from current TOU rates. Generally, they offer a simplified rate portfolio capable of meeting the needs of a wide range of customers.

<u>CA Energy Consulting Assessment:</u>

- Management's plan features customer charge modification to improve cost recovery in the near term and portfolio simplification in the future, without apparent loss of customer choice. DG and EV charging customers will have a demand rate and a super-off-peak TOU option that will have more efficient prices and improved revenue recovery than currently.

- The change to new TOU pricing periods reflects changing generation services cost patterns. The gradual approach to this change meets SRP's objective of gradualism without impairing the objectives of revenue sufficiency and customer fairness.

- Management's approach to TOU pricing, seasonal demand and energy pricing and time-varying energy prices offer the opportunity to match costs to customers better than flat rates. Management might wish to explore whether TOU customers on the new pricing periods will be less peak coincident and thus will have a lower cost to serve than other customers. If so, then there may be scope for the reduction of TOU prices and offsetting increases to the flat prices of E-23/24.

- Inclusion of TOU properties in the FPPAM price component is a step forward, as flat prices attenuate the TOU price signal.

- Management should review the question of how to price DG customers. Energy-only pricing that features energy prices in excess of avoided costs presents an overly favorable view of the cost savings to the utility and its members of investing in DG capability. This review, and any resulting rate revision, would help to avoid uneconomic bypass.

4.3 General Service Rates

The portfolio of General Service (GS) rates consists of two main rates, E-32, a TOU rate, and E-36, a seasonal declining block tariff, and two smaller rates. These latter are E-33, an experimental TOU rate with a three-hour super peak period and a pre-pay MPower rate, E-34, that plays the same role as the Residential MPower rate. Management's plan involves a class average bill increase of 1.3%, reflecting the current relatively high rate of return for the class.

Management proposes to modify immediately the main TOU rate's pricing periods to reflect changes in marginal cost, with peak hours now from 5 to 10 pm, resulting in a more rapid transition than occurs generally for Residential customers whose existing TOU price pattern is continued, although the existing TOU rates are frozen. Bill impacts are relatively high, with about 10% of customers experiencing bill increases greater than 10%.[48] (Note that bill impacts are measured in the absence of any price response to reduce the bill.) In contrast, the modest price changes applied to E-36 result in average bill increase of 1.3% and virtually no customers with impacts greater than a 10% increase.

[48] Roughly 1,100 of a sample of 11,400 customers with complete, clean data recorded bill increases of more than 10%. The customer population is about 15,000.

Modest price changes occur for the two minor rates as well. Management proposes to freeze E-33, the experimental TOU rate with super peak pricing, and to close it by November 2029.

The pattern of TOU price change, both seasonal and by time of day, is influenced by the changes in marginal cost. The impacts on TOU customers are more immediate than for Residential customers, as noted. The high average bill impacts are possibly a reflection of the reclassification of previously off-peak hours into shoulder and peak hours. This suggests that customers may modify their usage to reduce bill impacts. Another possibility is that the rate will result in customer movement between the TOU and the declining block rate, in both directions, as customers move to reduce their bills even before load shifting occurs in response to the daily price pattern. Thus, the full bill impact is difficult to predict.

One consideration for the future, as mentioned in the Residential section, is that the revised TOU option may result in customer self-selection based on load profile. The TOU customers may prove less costly to serve than the declining block customers, suggesting that price reductions for TOU customers may eventually be appropriate. This would further increase that rate's attractiveness and participation.

CA Energy Consulting Assessment:

- Management's actions with respect to the GS rate portfolio are modest in terms of price changes and vigorous in the immediate change to E-32's TOU time periods.
- The low average bill impacts are appropriate given the high rate of return earned on this class.
    - Relatively high bill impacts for the E-32 rate's customers suggests that SRP should expect movement between rates. This movement, sorting based on load profile, suggests further price revisions might be considered in a future price process, especially if customers depart E-32 in numbers. Such a pricing move would likely be cost-based.
- Management's proposed changes are in line with rate design objectives and with SRP objectives as well. The proposals recover adequate revenue and moves revenue collection in the direction of rate parity. Changes in rates reflect substantial changes in marginal generation services costs, and the main declining block rate's price changes are moderate. The changes establish a balance between the need to adapt through rate change and the need for gradualism in changes.

4.4 Large General Service Rates

SRP serves its large GS customers via a single main rate structure, with pricing differentiated by voltage service level. The three levels are secondary, primary, and substation, with rates E-61, 63, and 65, respectively. (Metering for substation customers occurs at the low side of the substation. Such customers are excused from paying primary distribution costs.) The utility also offers a rate for instantaneous interruptible load (E-66) and a separate rate for customers with peak demands greater than 20 MW and with load factors greater than 90% (E-67). This last group's pricing features large demand charges and offsetting low energy prices. New customers are required to pay demand charges that are based on billed demand that are the larger of actual demand and 80% of forecasted demand. This produces a structure suited to serving data centers due to its focus on fixed cost recovery via fixed charges.

Rates are seasonal TOU in structure and include a separate facilities charge. The purpose of this charge is to facilitate customer-specific or voltage service level-specific charges for distribution facilities cost recovery. Especially for larger customers, the facilities are customer-specific in configuration. For large customers, such charges improve the match between revenues and costs for this component of service, and are cost-effective as customer numbers are small.

As with the GS class, rates are stable in structure, except that the TOU price periods have been revised, and the same manner as those of the GS class. As before, changes in the pattern of marginal costs are the reason for the change. The change in price pattern is proposed to take place with this price process. Similarly, customer charges increase substantially, better reflecting customer-related costs.

Bill impacts for the class are moderate, averaging 1.3% within each rate and overall. For the rates with smaller customers, the highest bill impacts are moderate, with relatively few customers recording bill increases of more than 4%. For these customers, the increase in prices in the hours 5 to 10 pm appears not to have a significant impact.

SRP also currently offers a critical-peak pricing (CPP) pilot for large customers. This design provides customers a bill discount for being available to respond to short-notice indications of high market-based energy prices. Customer response to high prices facilitates bill control, as customer load reductions serve to ease tight reserve conditions. At present, no customers are participating in this design and Management is proposing to close this pilot due to longstanding lack of customer interest.

Management's proposals offer customers rate stability, and the TOU pricing period revision appears to not endanger this. Bill stability, cost recovery, gradualism are all features of the modest rate revisions for this class.

<u>CA Energy Consulting Assessment:</u>

- Management's price proposals for its largest customers meet SRP's rate design objectives of rate stability, gradualism, revenue sufficiency, equity, and cost relation. The CPP pilot, which has attracted no interest, is evidence of the utility's willingness to offer dynamic pricing for the purpose of controlling costs and limiting increases in capacity at a time of expected rapid growth. As well, the E-67 rate design appears tailored to the provision of cost-effective service to new large customers such as data centers.

    - The TOU designs appear to provide a close match between energy pricing and the average price level by season and time of day. Marginal cost considerations have been included in this class, as with others, in determining the pattern, if not the level, of energy prices. (The level must be set to recover financial costs.)

- Rates appear readily easy to unbundle should customers express a desire for increased retail choice. SRP's buythrough program, not included in this price process review, provides evidence of this capability.

4.5 Pumping and Irrigation Rates

SRP offers pumping rates to three types of customers: agricultural, municipal, and the SRP Association. Rate E-47 provides a seasonal flat rate with demand serving most customers. Rate E-48 offers a time-of-week option in which customers can lower their summer and summer peak demand charges in return for not pumping on a preselected day. A premium demand charge deters pumping on the "no-pump" day. Energy prices do not recognize this day.

Management proposes no change in rate structure for these rates, and modest price increases. The average bill increase for Rate E-47 is 1.3%, while the optional Rate E-48's average increase is 1.8%. A few customers on the former rate experience bill impacts in excess of 10%. That range is not mentioned for the latter rate.

CA Energy Consulting Assessment:

- Management's proposal appears to meet its rate design objectives. As with GS customers, rate structures are stable and price changes are moderate. The revised prices recover required revenues, are simple in structure and stable in revenues.

4.6 Lighting Rates

Metered lighting customers are served under the GS rates (E-32, 36). Unmetered customers are served under three separate rates defined by type. Lighting rates apply to traffic signal lights (E-54), public lighting (E-56), and private security lighting (E-57). All three rates are two-part in nature, consisting of a customer and an energy charge, which is flat and seasonal. The energy charge applies to estimated loads. The last two of these rates are currently identical in structure and pricing. All three feature summer and winter seasons.

Management's pricing plan involves no change in structure and modest price increases. Bill impacts are 2.2% for traffic signal lights, 1.3% for public and private security lighting. The class average increase is 1.3%.

CA Energy Consulting Assessment:

- Management's plan of price change only ensures rate stability and avoids any concerns regarding gradualism given the modest price increases. Marginal cost plays a role in the relative price increases between seasons, which results in lighting rates keeping up with other rate designs in terms of pricing methodology.

4.7 Riders

Riders at SRP provide charges or credits for activity whose costs largely are not covered by the CAS and thus not recovered in rates. Currently there are about two dozen riders, some available to customers on many rates and some few applicable to customers on only a few rates. (Lighting equipment riders are example of these last.)

Management's plan is to eliminate riders that currently serve no customers or that have been rendered obsolete by new riders and to update rates where cost changes suggest changes in the prices. Some of these provide access to market-based energy (interruptible and standby pricing, for example) and need regular updating, or a mechanism such as an index to automatically update pricing based on a publicly available set of values beyond the influence of the utility or any customer. In two cases Management proposes to update the index used.

Some riders play an important role in extending customer choice or rate alternatives. A newly proposed Carbon Reduction rider provides access to programs that pay to reduce carbon emissions in a variety of ways. Another rider, the newly named Energy Attribute Certificate rider, offers customers the option of "greening" their power by buying renewable energy certificates or alternative financial instruments tied to renewable energy. The Standby Service rider provides a way for a large customer with on-site generation to control costs arising from their low load factor. Management proposes to change prices, indexes, and the scope of service to respond to changes in customer preferences and in wholesale energy market prices. For riders of this type, a change to the rider must occur at the time of a price process review, but prices change between price processes in a predetermined fashion. These designs thus have the appearance of being adjustors, with the key that the price set is beyond the control of the utility and the customers whom it serves.

<u>CA Energy Consulting Assessment:</u>

- Management's proposals for rider revisions are sensible in that they cover the entire set of riders and remove those that no longer are needed. For new and continuing riders, the proposed revisions observe the rules of rider applicability – no utility control of prices between price processes – but offer timely updating of prices to customers seeking these services.
    - The riders also extend the portfolio of rates in useful ways.

4.8 Summary

Management's rate design challenge in the current price process stems from a number of changes since the last price process in 2019 that required a response. The significant change of peak time period from afternoon to evening growing out of the rise in solar generation capability is the most notable of these. Customer site generation also exerts pressure on Management to develop alternative ways to recover fixed costs from these customers, since the volumetric approach of the current design leads to under-recovery and the risk of cost shifting to others. For these and other reasons, then, a simple proportional increase in the prices of existing rates would have been insufficient in meeting these rate design challenges.

The proposed response by Management to the peak period time change is to move GS and large GS customers to the new time period configuration upon approval by the Board at the effective date of the rate change (November 2025) and to offer Residential customers a similar TOU option that permits customers four years (until November 2029) to move to the new rate. For Residential customers, this allows time to respond and to compare the new TOU designs (E-16 and 28) along with the traditional seasonal flat rate (E-23). The new time periods also identify the period of very low energy prices (midday 8 am to 3 pm) a window wide enough to permit customers to shift substantial load and reduce cost. The only regrettable aspect of the change, which is beyond SRP's control, is that there is no nighttime period of very low cost that can be used for EV charging. As compensation, the very low midday costs might help to stimulate commercial EV charging.

As for changes in customer charges, Management proposes to simplify Residential and Small General Service charges by making them identical within each class but then differentiating them in the Residential class on the basis of amperage rating and type of structure, both sources of differences in cost to serve.[49] The effect is to move charges in the direction of customer-related cost while providing a mix of cost difference and rate design gradualism in setting the prices.

The result of these changes is that bill impacts are generally moderate, with bill increases in the upper end of the distribution of outcomes being generally rare. Some Residential and large GS customers have bill increases in excess of 10% but price response by customers to the change in the timing of the peak offers some degree of cost control and, at the same time, helps the utility to control its costs associated with peak demand.

Management's proposals with respect to riders include closing unused or obsolete riders and modifying others to improve their ability to reflect in a timely manner the costs that they are intended to cover, in particular by improving the market price references for some generation services and renewable energy offers. The revised, shortened set of riders still expands the range of customer choice with respect to renewable pricing and niche program interests. In particular, the proposed expansion of eligibility for the Economy Discount to 200% offers the opportunity for newly eligible customers to reduce their electricity costs. Notably, the discount is a lump sum, which gives all customers the same price incentives to use or control usage of electricity, depending on the time of day.

5. SUMMARY OF FINDINGS

Management has submitted price proposals consisting of a Cost Allocation Study, a Marginal Cost Study, and a Price Adjustment document for review and approval by the Board of Directors of Salt River Project. Our review has led to the general conclusion that the Management team has responded with methodology and rate design changes that respond to changes in the business environment while meeting the rate objectives of the utility.

5.1 Cost Allocation Study

The CAS provides continuity with the previous price process, using largely the same methodology as previously, but with revisions that respond to changes in SRP's business environment and practices. Management continues to compute revenue requirements based on a forecast test year (May 2025 to April 2026), with requirements based on its most recent fiscal year plan, with appropriate adjustments. The study is conducted on a "cash" basis, a well-established approach to developing revenue requirements. Additionally, the CAS model applies accepted methods of functionalizing, classifying, and allocating costs to retail rate classes.

Management proposes one significant change to its functional classification methodology. The rise in demand-related pricing in purchased power contracts has caused the team to split FPPAM

[49] It should be noted that the monthly customer charges for rates E-32 and 36 have been the same for some time. Note also that the Residential and General Service M-Power customer charges are currently the same. The proposal makes the Residential M-Power customer charges tiered and identical to other Residential charges while the GS M-Power customer charge moves to $30 per month, the Tier 2 value of the Residential rate.

costs into demand-related and energy-related categories. This is an improvement over the energy-related approach used previously, as it improves recognition of peak coincidence by class in cost classification.

An additional change of methodology occurs with respect to distribution cost. Management has made use of new cost information to improve the classification of these costs as either demand- or customer-related. In brief, the methodology of classification has not changed but the quality of the supporting data has improved.

Management has also updated its approach to the allocation of generation demand-related costs by recognizing that the period of maximum loss of load probability has shifted, with the rise of solar generation, to the early evening. Their use of LOLP-weighted peak demand improves upon the previous allocation approach.

An additional modification proposed by Management smooths customer-related costs across rates within the Residential and General Service rate classes. This change results from a prior agreement and acts to reduce bill impacts if a customer moves from one rate to another. The change is slightly unusual in that the computations occur in the CAS but the outcome would not be different had the change been performed outside the model. This approach is a matter of practical convenience but does not materially alter the CAS methodology.

The revised methodology, then, responds to changes in the utility's circumstances in sound ways that conform to costing practice, and improve the allocation of costs to classes, and within classes. Overall, SRP's CAS study satisfactorily allocates costs to rate class, and it underlying functional classification provides a sound basis for ratemaking with respect to setting customer, demand, and energy prices. Additionally, the allocation of FPPAM costs has been materially improved. The CAS results also offer guidance in determining rate of return, under both current and target revenue requirements, helping Management to ensure that rate of return differences across classes are reduced in this price process.

5.2 Marginal Cost Study

Management's marginal cost study continues existing practices and updates values in response to recent information. The study estimates the marginal energy-, demand-, and customer-related costs to serve the utility's customers according to established methods.

Energy-related marginal costs are a combination of generation, transmission, and distribution costs, each estimated by separate methodologies. Generation costs are related directly to market clearing prices from the WEIM energy market, while transmission and distribution cost estimates arise from line loss studies.

Demand-related marginal costs are derived from economic carrying charge computations associated with capacity costs of generation and growth-related transmission, substation, and distribution projects. Again, this methodology is well established. Generation capacity costs are associated with combustion turbine generators along with solar and battery storage devices. Transmission and distribution costs are based on recent historical investment costs.

Customer-related marginal costs are based on internal data associated with meters, billing, and customer services. Again, the computational methods are well established within the industry.

Lastly, SRP makes appropriate use of its marginal cost estimates to guide the development of TOU pricing periods and price ratios, and to influence the setting of price levels, thereby making prices more efficient conveyors of resource cost information to customers.

5.3 Rate Design Proposals

Management's price proposals are based on sound embedded and marginal cost principles and practices. The proposals also respond to rate design challenges that have been emerging since the previous price process. These proposals largely meet the Board's strategic pricing objectives and general criteria for successful rate design.

SRP's rates continue to make use of seasonal three-period TOU rate design options, and retain the Residential seasonal design, dropping the mild inclined block feature. Management has proposed two modifications to its designs.

First, the change in marginal cost patterns has caused Management to modify its TOU rates to create an evening peak period and to make available a midday off-peak period corresponding to predominantly low marginal costs at that time. Management proposes that these new pricing periods take effect at the upcoming effective date in November 2025 for General Service and Large General Service customers. For Residential customers, the proposal is to freeze current rates with the old TOU price pattern and open up the new options with the same timing as those serving GS customers and Large GS customers. According to the plan, the frozen rates will be closed no later than November 2029, allowing customers four years to plan their response to the new pattern and choose a new rate. This approach will also likely help to control customer service adjustment and support costs for the utility.

Second, Management proposes to raise monthly customer charges to move them closer to customer-related costs. This helps to reduce energy charges, bringing them closer in line with energy-related costs. Additionally, Management has reconfigured its Residential customer charges, smoothing them across rates, but also differentiating them by customer type, based on amperage rating and type of dwelling. These changes reduce bill impacts should customers move from one rate to another and also move cost recovery in the direction of cost to serve.

These rate modifications help SRP to respond to relatively rapidly changing cost and wholesale market circumstances, and improve pricing for customers with new end uses such as solar generation and electric vehicle charging. More generally, the rate design revision assists the utility to meet its strategic objectives as follows:

- **Sufficiency:** the proposed increase in revenue requirement will permit SRP to cover its forecasted cost increases.
- **Cost Relation:** the modifications in costing methodology, and in the pattern of TOU rates and level of customer charges, will improve the match between customer bills and cost to serve both between and within classes.
- **Equity:** the smoothing of certain costs and the broad retention of rate structure will facilitate acceptance by customers, despite the fact that Residential and small GS rates will be frozen and eventually closed.
- **Choice:** the introduction of replacement rates similar in structure but different in price timing appears designed to meet the needs of increasingly diverse customers. Customers with emerging needs for support for their end uses will find rate designs that meet those

needs via off-peak pricing options and energy prices that are a closer approximation to marginal cost.

- **Gradualism:** most customers will experience moderate bill increases that are fairly close to the overall proposed revenue increase request once the reduction in FPPAM price is taken into account. Customers with the largest expected bill increases will have the ability to reduce the bill impact via price response, shifting load away from the new peak pricing periods to lower cost periods.

Overall, Management's price proposals satisfy the general criteria for a successful rate design since they provide not only for revenue sufficiency and rate design acceptability, but also improved price efficiency, rate stability (since the structures are not changing much other than the price period timing), and fairness (since the degree of cross subsidy is being reduced via the monthly customer charge increases). CA Energy Consulting finds that Management's proposals meet these rate design requirements and provide satisfactory cost support for the utility's price structure and price level recommendations.